2008 Asset Plan

Draft

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1 Asset Category Overview

1.1 Description of Assets

Transmission Services provides reliable open access, non-discriminatory transmission service on the Bonneville Power Administration (BPA) transmission network for utilities, generators, and power marketers consistent with various regulatory requirements. This is done through marketing and selling transmission products and services. Transmission Services provides asset management services for the transmission assets of the Federal Columbia River Power System (FCRPS) including transmission system planning, design, construction, operations and maintenance.

BPA owns and operates about 75% of the Pacific Northwest's high voltage electrical transmission system. The system includes more than 15,000 circuit miles of transmission line and 285 substations. Lines network across 300,000 square miles in Oregon, Washington, Idaho, Montana and sections of Wyoming, Nevada, Utah and California providing connections to transmission systems from the Northwest to Canada and California. Lines are strategically located to reach all sectors of the Northwest – including publicly owned and investor owned utilities, independent power producers and direct service industries – with the potential to access 95 percent of the Northwest's 10 million population. The system serves a peak loading of about 30,000 megawatts and generates more than $750 million a year in revenues from transmission services.

For Asset Management and Planning purposes, Transmission Services' assets are grouped in seven major categories:

- Expansion
- Lines
- Station
- System Protection & Control
- Power System Control
- Control Centers
- Tools & Equipment Acquisition Program (TEAP)

The expansion portfolio is treated as a separate asset category until energization, at which time the combined equipment installed as the project(s), are then managed within their respective asset groups to achieve optimum life-cycle costing.

2 Asset Plan Scope, Strategic Direction & Objectives

2.1 Asset Category Long-term Outcomes

The agency's strategy map, mission and vision statements provide high level direction on managing the health, performance, costs and risks of assets. The long-term outcomes are intended to translate the agency's vision, mission, and strategic objectives into terms that can be operationalized and measured.

Long term outcomes for Transmission's assets are to meet:

- Transmission reliability standards
- Transmission availability requirements
- Transmission adequacy guidelines
- Development expectations in regional plans
- Environmental requirements
- Regulatory and legal requirements
- Generation integration and transmission service requests
- Safety and security standards

The above outcomes are to be managed at "least life cycle cost."

2.2 Asset Plan Scope

The objective of the asset plan is to identify near and long-term activities and investments needed for the assets to meet BPA's long-term objectives. Capital and expense investment plans are optimized and prioritized based on:

- the current condition and capability of our assets
- the predicted demands that may be placed on our assets
- the desired performance of our assets
- the risks to meeting the performance targets of our assets
- least life cycle costs

Additionally the asset plan documents areas of improvement needed for Transmission to most effectively manage our assets in the future.

Finally, the Asset Plan will be used as a communication tool for Employees, Customers and Stakeholders. The spending levels identified in the Asset Plan will be used in this year's Integrated Program Review being lead at the agency level.

2.3 Asset Plan Logic

Transmission Services has two distinct but interrelated asset planning processes, how we expand the transmission system and how we manage or sustain our existing assets. Expansion investments are capitalized. Sustaining investments are a combination of capital replacements, expense refurbishments and expense corrective and preventative maintenance programs. The ultimate goal of each of these processes is the provision of safe, reliable and cost-effective transmission services.

The nature of the two processes requires very different asset groupings. Expansion planning processes consider assets at a system level. Sustaining planning processes consider assets on an asset or component specific basis. Following is a breakdown of the asset groupings for each major process.

Expansion

The expansion capital portfolio consists of investments required to meet load growth, generation interconnection, or congestion relief, which improve system reliability or increase capacity. Projects range from minor facility upgrades to major transmission line and substation additions. Expansion projects are grouped by:

Main Grid

The Main Grid consists of the 500 kV transmission and substation facilities as well as some 345 kV and a few 230 kV facilities. BPA has over 5500 circuit miles of transmission line in this category. Several of the northwest's major interties and paths are included in this category.

Main grid projects are further grouped by Major Projects and Large Load Centers.

Area & Customer Service

The Area and Customer Service asset category consists of facilities, typically 230 kV and below, which function primarily to serve customer loads. BPA has over 9000 circuit miles of line in this category. This portion of the Network serves load areas across Oregon, Washington, Idaho, and Montana.

Upgrades and Additions

This category consists of additions to high voltage equipment or control/communications equipment or replacement of existing facilities with new facilities that have additional capacity or capabilities. Some examples of items in this category include: adding high voltage switchgear at a new tap point or upgrading a transmission line with higher capacity conductor.

Sustaining

The sustaining portfolio consists of capital replacement programs, expense refurbishment programs and preventative and corrective maintenance programs. Replacement and refurbishment Investments are required to maintain overall asset health and therefore, maintain system capacity and performance. Typical projects include the replacement of damaged, aging or obsolete equipment or technology. The Replacement Capital portfolio also includes projects that are required to reduce risks and meet regulatory standards. Examples of these include seismic upgrades, spill containment, and fire risk reduction programs.

Assets are grouped as follows:

Lines

The transmission system consists of about 15,200 circuit miles of high voltage transmission lines suspending about 70,000 miles of conductor on 89,560 structures. The power lines are composed of numerous conductor and ground wire carried on both lattice and pole structures composed of steel, aluminum, and wood materials. Fiber optic cables are carried by some power line structures carefully located to ensure efficient co-existence of both bulk transfer systems. The preponderance of the overhead asset is contained either on the 500 kV primary power delivery grid, or the 230 kV and 115 kV under lying grid supporting most of the interconnections with customers.

Station

Substation assets consist of circuit breakers, circuit switchers, fuses, and disconnect switches (typically grouped as Switchgear); power transformers, surge arresters, instrument transformers, shunt and series reactors, and shunt and series capacitors. Also included are certain unique or specialized equipment such as Static VAR Compensators (SVC), Gas Insulated (GIS) equipment, a High Voltage DC converter, and a Thyristors Controlled Series Capacitor (TCSC).

System Protection & Control

Protection and control assets consist of all protective relaying, monitoring, metering and control systems at the transmission substations. These assets protect transmission equipment from damage due to electrical and mechanical faults, ensure stability and reliability of the transmission system, protect the public and personnel and provide local and remote control and monitoring of transmission equipment. These assets also provide accurate metering and control of the electrical grid.

Power System Control

BPA operates an extensive telecommunications and control system vital for the safe and reliable operation of the transmission system. The telecommunications system covers BPA's 300,000 square mile service territory in the Pacific Northwest utilizing a mix of technologies. A variety of control systems is utilized to provide high-speed clearing of power line faults, automatic response to changing system conditions, and visibility and control of substation equipment and generators by dispatch. Together these systems provide the data and controls necessary to maximize transfer capacity and stability of the transmission system.

Control Centers

Transmission owns and operates two fully redundant Control Centers: Dittmer CC and Munro CC. The Control Centers provide secure and highly available dispatch locations, infrastructure, systems and tools to support the safe and reliable control and operation of the Northwest power system.

2.4 System Sparing Policy

The maintenance and material management organizations maintain an inventory of spare parts and equipment in order to keep the system operating. Spare parts are used in the course of preventive maintenance services (such as overhauls) and for minor equipment repairs. Spare equipment is utilized to restore service following major equipment failures. Materials Management works in partnership with Maintenance to ensure appropriate spare equipment inventory is available.

Location of Spares

A combination of methods is used for stocking spare parts and equipment. Stocked in a central location are parts and equipment which are used infrequently and for which there are few needs in the districts. Centralized storage does require a longer response time when spares are needed. Parts and equipment which are used frequently are located at various field locations, substations and/or District headquarters.

Stocking Levels

Each maintenance group establishes stocking levels of spare parts based on historical usage, criticality of equipment, experience with the equipment, shelf life, and the availability and delivery time of vendor stock. Annual reviews of parts stock are conducted to assure the integrity of the inventory. The levels of spare equipment are reviewed for adequacy annually. Stocking levels of equipment and parts are maintained so that contingency response guidelines can be met. Materials are obtained for planned preventive maintenance services on an as needed basis.

Special Requirements

Spare parts and equipment must be stored in facilities suitable to maintain the proper operating quality of the equipment. Special requirements may include indoor storage or oil spill containment for oil filled bushings, breakers, and transformers. Heat, gas blankets, etc. are provided for equipment storage as required.

Hazardous materials must be stored in a manner meeting state and federal requirements.

2.5 Summary of Standards and Requirements

BPA is a member of the Western Electricity Coordinating Council (WECC), which is a regional member of the North American Electric Reliability Corporation (NERC). As a WECC member, BPA plans and operates the transmission system in accordance with NERC planning and operating standards, augmented by WECC and BPA's own Reliability Criteria. The NERC/WECC Planning Standards establish the envelope within which members plan and operate their systems. Regional characteristics (geography, weather, etc.) often dictate regional or individual utility differences or more stringent standards. BPA's own criteria contains additional detail relevant to our system (for example, recognizing the impact of extreme cold weather in winter) while still conforming to the broader NERC/WECC Planning Standards. Compliance with these standards is one of the driving factors behind capital investments on the transmission system.

Transmission Services applies the NERC/WECC Planning Standards to ensure reliability in planning the transmission system. NERC defines reliability in terms of both adequacy and security.

Adequacy:
The ability of the electric system to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security:
The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

The NERC/WECC Planning Standards detail the system performance criteria used to address these two objectives. The Energy Policy Act of 2005 and subsequent regulations made adherence to the NERC standards mandatory. Over the past three years NERC has been revising all standards with the objective of making requirements clear and measurable. In many cases new requirements have been identified and some criteria are more stringent leading to new investments.

2.6 Summary of Critical Assets

To focus attention on the most important assets, we identify those that are critical. For the 2008 Asset Plan Transmission Services' list of critical physical assets are synonymous with the list of "significant equipment" contained in Operating Bulletin 19 (OB-19). This list is comprised of any system equipment which when taken out of service may require an Operating Transfer Capacity (OTC) reduction to assure reliable operation on a defined transmission path. This includes outages that alone might not affect capacity, but could under credible conditions, in combination with other outages, have an impact.

Nevertheless, Transmission is working on another method to identify critical assets. For example, not all the load service areas are covered with the OB-19 list. Most of the Puget Sound and Portland areas are covered but the Olympic Peninsula and Southern Oregon coast are examples of load areas that do not have equipment listed in OB-19.

The BPA Priority Pathways team is developing a consistent methodology to rank BPA transmission paths. The end result will be a critical equipment list and a methodology that will allow for consistent updates in the future. Transmission Services plans on using the results of the Priority Pathways team to define critical assets for asset planning in the future.

2.7 System-level Metrics and Targets

Transmission Services currently sets system-level performance targets and metrics each fiscal year. FY08's system targets are:

- **<u>WECC Maintenance</u>**
  A) Complete 95 percent of WECC required maintenance by end of the fiscal year; B) verify the remaining 5 percent is scheduled for completion to meet the requirements for the annual WECC certification; and C) WECC certification for CY2008 is successfully turned in January 2009.

- **<u>Reliability Compliance (“child” target of Transmission Reliability)</u>**
  (1a) No more than one instance of a "High Risk Factor" violation with a "high" or "severe" violation severity level (level 3 or more); (1b) 100% of BPA submitted, WECC approved or revised mitigation plan milestones are completed for technical compliance and 95% of WECC approved or revised mitigation plan milestones are completed for documentation (may be revised following WECC readiness or WECC compliance audits).

- **<u>No Involuntary Curtailments of Firm Load (child of Transmission Reliability)</u>**
  No Involuntary Curtailments
  (2) experiencing no involuntary curtailments of firm load due to a reliability violation, transmission system security breach or cascading outages originating on the BPA system.

- **<u>Transmission Availability</u>**
  BPA's most important transmission lines (Category 1 and 2) are available for service at least 98.0% of the time. (Key T Target, KAT)

- **<u>SAIFI - Outage Frequency</u>**
  System Average Interruption Frequency Index (SAIFI) - Average number of automatic outages by BPA line category.

- **<u>SAIDI - Outage Duration</u>**
  System Average Interruption Duration Index (SAIDI) - Average number of automatic outage minutes by BPA line category.

- **<u>Vegetation-Related Outages</u>**
  Report of number of outages with a cause related to vegetation (trees) for transmission lines 200 kV+. Includes outages for tree-growth, blown, or cut, characterized as inside the BPA right-of-way.

3 Current Condition, Capabilities, Demands and Investments

3.1 EXPANSION

3.1.1 Objectives

Transmission Services Growth Capital portfolio is comprised of the capital investments required to expand and reinforce the transmission system to meet the forecast requirements of BPA and other customers over the 10-year planning period to meet adequacy and reliability long term outcomes.

The system expansion and reinforcement reflected by this Growth Capital portfolio is driven by service requests, including: (1) Contractual obligations for load service; (2) PTP contracts between BPA and other customers including BPA Power Services; (3) loads and resource interconnections; (4) mandatory Compliance with NERC/WECC Planning Standards; and (5) other agreements.

3.1.2 Key Drivers

Interconnection of New Generation

IPP's may request interconnection to BPA's system for the purpose of making sales to other purchasers. IPP connections typically include a combination of direct assignment facilities which are fully paid for by the IPP and Network Upgrades which are funded in accordance with the Wholesale Transmission Service (WTS) and Open Access Transmission (OATT) tariffs. BPA has no control over the timing or location of IPP's interconnections.

Load Growth

The primary load centers within the BPA system are located west of the Cascade Mountains in western Washington and western Oregon. The Puget Sound load area is one of the largest load areas within the BPA system. This area contains several major industries and cities including: Seattle, Tacoma, Bellingham, and Bellevue. BPA supplies four major utilities in the Puget Sound area:

- Puget Sound Energy (PSE)
- Tacoma City Light (TCL)
- Seattle City Light (SCL)
- Snohomish PUD

The other major load area is within the Willamette Valley. Portland, Salem, and Eugene are the main load centers within the Willamette Valley. BPA supplies the following major utilities within the Willamette Valley:

- Portland General Electric (PGE)
- PacifiCorp (PACW)
- Springfield Utility Board
- Eugene Water and Electric Board (EWEB)

Existing Resources

The following are major generation resources in the BPA system:

- Hydroelectric generation on the Columbia River
- Hydroelectric generation on the Snake River
- Columbia Generation Station (Nuclear)
- Coal generation in Montana and Centralia, Washington
- Thermal generation west of the Cascades
- Wind generation primarily east of the Cascades

The BPA load varies over the course of a day as customers increase and decrease their consumption of electricity. The Northwest has historically been a winter peaking system because heating of homes and buildings is a primary load. Conversely, California tends to be a summer peaking load due to the large air conditioning load on the system.

During the winter, when Northwest loads are peaking, the Northwest sometimes imports power from California via the Pacific AC and DC interties.

During the summer, when California loads are peaking, the Northwest often exports large amounts of power to California via the Pacific AC and DC interties.

BPA’s peak loads, plus any firm transmission service obligations, are used to determine the bulk system reinforcement requirements. Around the Northwest, load growth occurs at different rates depending on the specific geographic area.

Customer Requested Projects

From time to time, a BPA customer may request changes to the transmission system for their own benefit. These types of requests may include increased service levels beyond that which is normally provided, or relocation of transmission system equipment (e.g., lines and towers). The customer requesting the project would pay or cost-share in the project, but BPA continues to own the assets.

Operations & Maintenance Flexibility

Operating Bulletin #19 (OB-19) designates critical transmission system equipment which requires a 45-day process for scheduling maintenance outages. Prior to "planned" outages being granted on OB-19 lines and equipment, system conditions have to be analyzed and appropriate adjustments made to cut-plane and Intertie capacities. When "unplanned" outages occur, immediate, and severe curtailment of Intertie capacities may be placed in effect until studies can be completed. A long-term outage planning process, based on analysis, has been developed to meet the needs of both system reliability and the market place. Although the new requirements and processes are successful, they have the added effect of limiting available outage windows for construction and maintenance activities on our system. Therefore, some limiting transmission system configurations, constrain our ability to operate and maintain the transmission system, in order to meet our strategic business objective of system availability.

O & M flexibility projects are considered for funding, in order to remedy these operation and maintenance limitations, and improve availability of lines and equipment, with special emphasis on OB-19 lines and equipment. Most O & M Flexibility upgrades will address the following issues:

- Forced outages to collateral lines and equipment beyond that of the desired equipment or lines during maintenance
- Excessive equipment or line clearing during fault conditions due to lack of protective devices
- Reduced maintenance windows due to critically of lines or equipment

Typical O & M Flexibility projects could include any of the following:

- Bus tie breakers
- Bus sectionalizing breakers or disconnect switches
- Transformer high side breakers
- Terminal breakers
- Additional redundant protective relaying

3.1.3 Expansion Portfolio

The Expansion portfolio is composed of the following asset groups:

- Main Grid
- Area & Customer Service
- Upgrades & Additions

<u>Main Grid</u>

BPA's Main Grid consists of the 500 kV transmission and substation facilities as well as some 345 kV and a few 230 kV facilities. BPA has over 5,500 circuit miles of line in this category. Several of the northwest's major interties and paths that BPA uses for scheduling, are included in this category.

Some of the key drivers for expansion of the Main Grid, include:
- Load Service/Load Growth served by network transmission
- Compliance with mandatory Reliability Standards
- Congestion Relief
- Interconnection of new Generating Resources
- Point to Point (PTP) transmission service requests
- Improved Operational and Maintenance Flexibility

Main Grid Projects

The Main Grid can be divided into sub-categories based on the magnitude of load in the area and further by geographic locations within the system. These categories will be described in the sections which follow.

Major Load Areas

Major Load Areas are those which span a broad geographic area and incorporate several load centers with a combined total load in the range of thousands of megawatts (MW).

Puget Sound Area / West of Cascades - North

The Puget Sound area includes the load area west of the Cascades Mountain range roughly from Chehalis, Washington to the Canadian border. The transmission system in this area serves the major Seattle/Tacoma Metropolitan Area in Washington, as well as many outlying communities such as Aberdeen, Bellingham and Everett.

The total peak area load in Puget Sound is approximately 12,000 MW. Customers served within this area include: Puget Sound Energy, Seattle City Light, Snohomish PUD, Tacoma Public Utilities, Tacoma Mutuals, Whatcom County PUD, Grays Harbor PUD, the US Navy, Trans-Alta (Generation Integration at Centralia/Big Hanaford), and several other smaller customers.

There is a total of over 5200 MW of generating resources in the Puget Sound area. This is a combined total of resources owned Puget Sound Energy, Trans-Alta, Seattle City Light, Tacoma Public Utilities, and Snohomish PUD). The remainder of the load, not covered by these resources, is served by power imported on the major transmission sources to the area.

There is a total of approximately 6,600 MVAR of reactive support in the Puget Sound load area.

There are no projects identified for this area in the fiscal year 2009 to 2010 timeframe.

Projects forecast in this area include:

Seattle Area 500/230 kV Transformer Bank

Description:

Install a new 500/230 kV Transformer Bank in the Puget Sound Area.
The project will also involve development of a 500 kV yard at the site chosen for the transformer installation.

Key Drivers:

- Puget Sound Area load growth

Issues Being Addressed:

Load growth in the Puget Sound area

Discussion of Alternatives:

The full plan of service for the project has not been developed yet. Alternatives will be considered as part of that development.

North Cross Cascades Reinforcement – Phase I

Description:

Add series compensation to the Schultz-Raver 500 kV lines No.3 and 4

Key Drivers:

- Main Grid Voltage Support
- Service to the Puget Sound Load Area
- System Reliability
- Congestion Relief

Issues Being Addressed:

Load growth in the Puget Sound area
Additional capacity to move resources from locations east of the Cascades to load centers west of the Cascades.

Discussion of Alternatives:

The full plan of service for the project has not been developed yet. Alternatives will be considered as part of that development.

WILSWA Area / West of Cascades - South

The WILSWA (Willamette Valley and Southwest Washington) area includes the load area west of the Cascade Mountain range from approximately Longview, Washington to the Oregon/California border. The transmission system in this area serves the major Portland/Vancouver metropolitan area as well as several other communities down the Willamette Valley such as Salem, Eugene, Roseburg, Grants Pass, and Medford.

The total peak area load for WILSWA is approximately 9,500 MW. Customers served within this area include: Portland General Electric, PacifiCorp, Clark Public Utilities, Cowlitz PUD, Clatskanie PUD, Columbia PUD, Skamania PUD, Tillamook PUD, Central Lincoln PUD, Wahkiakum PUD, Emerald PUD, Western Oregon Electric Co-Op, Blachley-Lane Electric Co-Op, Lane Electric Co-Op, Douglas Electric Co-Op, Salem Electric Co-Op, Consumers Power Electric Co-Op, Coos-Curry Electric Co-Op, and the cities of Eugene, Springfield, Monmouth, McMinnville, Forest Grove, Canby, Cascade Locks, Bandon, Drain and Ashland.

There is a total of approximately 6,100 MVAR of reactive support in the WILSWA load area.

There is a total of over 5000 MW of generating resources serving the greater WILSWA load area. This is a combination of thermal and hydroelectric resources owned/operated by the Corps of Engineers, Clark Public Utilities, Portland General Electric, PacifiCorp, Cowlitz PUD, and Eugene Water and Electric Board. The remainder of the load, not covered by these resources, is served by power imported on the major transmission sources to the area.

Projects forecast in this area include:

Allston 500 kV Shunt Capacitor Addition

Description:

Install a new 500 kV Shunt Capacitor Bank at Allston Substation.

Key Drivers:

- WILSWA Area load growth

Issues Being Addressed:

Load growth in the Portland and Willamette Valley vicinity.

Discussion of Alternatives:

Locating the capacitors at other sites was considered, but did not prove as effective for voltage support as Allston.

Large Load Areas

Large load areas are served mostly by 230 kV facilities as part of an interconnected network. The total magnitude of load in these areas is typically 300 MW or greater.

Olympic Peninsula

The Olympic Peninsula load area is located north of Olympia and Aberdeen, Washington and west of Puget Sound. Transmission Facilities in the Olympic Peninsula serve the larger communities of Shelton, Bremerton, and Port Angeles, Washington as well as many smaller communities in between (e.g. Port Townsend, Sequim, Port Ludlow, etc.).

The total area load in the Olympic Peninsula is approximately 1200 MW (winter peak). Customers served within this area include: Clallam PUD, Mason PUD Nos. 1 and 3, the City of Port Angeles, Port Townsend Mill, Puget Sound Energy, and the U.S. Navy.

There is a total of approximately 800 MVAR of reactive support in the Olympic Peninsula load area.

There is very little local generation (less than 30 MW) within the Olympic Peninsula load area. Therefore, most of the power to serve area loads, must be imported on the major transmission sources to the area.

This area has been a site of rapid load growth in recent years. The primary concern in this area is maintaining reliable service to these growing loads.

Projects forecast for this area include:

Olympic Peninsula Reinforcement

Description:

Remove the Olympia-Shelton No.1 115 kV line up to the Dayton Mason County Tap to provide right-of-way for building a new line. Split the Olympia-Satsop No.2 230 kV line at a point approximately 6 miles west of Olympia. Construct a new 14 mile double circuit 230 kV line from Shelton to connect with the split Olympia-Satsop No. 3, 230-kV line. This will create the Olympia-Shelton No. 5, 230-kV and the Satsop-Shelton No. 1, 230 kV.

Key Drivers:

- Load Growth
- Voltage Stability Performance

Issues Being Addressed:

Load growth in the Olympic Peninsula area

Discussion of Alternatives:

- Do Nothing – This is unacceptable because of load loss and potential voltage instability as well as NERC Criteria violations will result
- Non-Wires Solutions – Conservation is being implemented and a pilot program for demand-side management was tested.

However, none of these measures solve the problems for the critical double contingencies which drive the project

- New 500 kV single circuit line to Shelton – This option does not solve the voltage instability problems in the area
- New 230 kV double circuit line to Shelton – This is the preferred alternative.

Central Oregon

The Central Oregon load area includes the area east of the Cascades Mountain range roughly from Maupin to La Pine, Oregon. The transmission system in this area serves the cities of Redmond and Bend, as well as many outlying communities such as Madras, Prineville, Sisters, and Lapine. The total area load in Central Oregon is over 600 MW (winter peak). Customers served within this area include: PacifiCorp, Central Electric Co-Op, Harney Electric Co-Op, and Mid State Electric Co-Op.

There is approximately 100 MVAR of reactive support in the Central Oregon load area.

There is very little local generation within the Central Oregon area so loads are primarily served from resources outside the area via imports on the transmission system.

Both summer and winter are critical seasons for this area. Winter loads are high due to heating demands. However, there is a potential for facility overloads in summer when higher ambient temperatures restrict the ratings of facilities. This area has been the site of rapid load growth in recent years. With growing loads, some of the transmission facilities in the area are reaching the limits of their capacity. The primary concern in this area is maintaining reliable service to these growing loads.

Projects forecast for this area include:

Redmond 230/115 kV Transformer Bank Addition

Description:

Expand Redmond Substation and install a new 230/115 kV transformer bank.

Key Drivers:

- Rapid load growth in the Central Oregon area
- System Reliability

Issues Being Addressed:

Additional source of transformation to serve growing loads in the Central Oregon load area.

Discussion of Alternatives:

Alternatives included:
- Alternate sites (substations) for the transformer addition
- Adding shunt capacitors for voltage support to defer the need date for the transformer.

Adding the transformer at Redmond was selected as the preferred plan of service because it maintains reliability to growing loads.

Central Oregon 500/230 kV Transformer Bank Addition

Description:

Install a new 500/230 kV Transformer Bank in the Central Oregon Area (potentially locations being considered are at either Ponderosa or Pilot Butte Substation).

Key Drivers:

- Load service to growing Central Oregon area loads
- System Reliability

Issues Being Addressed:

Load growth in Central Oregon

Discussion of Alternatives:

The full plan of service for the project has not been developed yet. Alternatives considered include locating the new transformer at Ponderosa or Pilot Butte Substations. Other alternatives will be considered as the plan of service is developed.

Tri-Cities

The Tri-Cities area is located in South Central Washington and encompasses the cities of Pasco, Richland, and Kennewick, Washington – all of which are located along the Columbia River. The transmission system in this area serves these cities, as well as the rural irrigation loads of Big Bend Electric, Benton PUD and Benton REA and many other smaller rural towns near the Tri-Cities area. The total area load in Tri-Cities is approaching 900 MW. Customers served within this area include: Franklin County PUD, City of Richland, Benton County PUD, Benton REA, Big Bend Electric Co-Op, Columbia REA, South Columbia Basin Irrigation District, U.S. Bureau of Reclamation, PacifiCorp, and Avista.

There is a total of approximately 240 MVAR of reactive support in the Tri-Cities load area.

Generating Resources, which support loads in the Tri-Cities area, include: hydroelectric plants at Ice Harbor, Chandler, and Canal generation (at Scotney, Glade & Ringold) and local wind farms (Nine Canyon & Nine Mile). The combined total of these projects is approximately 900 MW.

Increasing constraints on the operation of hydroelectric projects in the area, limit the ability to re-dispatch resources to off-load constrained transmission paths. One of the primary sources to the area, the Sacajawea transformer bank, has been out of service for over a year, and due to long manufacturer lead times, a replacement won't be available until 2009. This further limits the operational flexibility in the area. Maintaining reliable load service is the main issue for the Tri-Cities area.

Projects forecast for this area include:

Tri-Cities Area Reinforcement

Description:

Add a 115 kV bus sectionalizing breaker at White Bluffs Substation and upgrade a short section of 115 kV line.

Key Drivers:

- Load service to growing loads in the Tri-Cities area

Issues Being Addressed

Load growth in the Tri-Cities area.

Discussion of Alternatives

Upgrading multiple lines in the area to higher capacity was another alternative that was considered. However, this option was not as cost effective as the recommended plan of service.

Future projects:

Future projects in the Tri-Cities area are currently under study.

Mid-Columbia Area

The Mid-Columbia area includes the load area in central Washington east of the Cascades Mountain range roughly from south of the Upper Columbia River basin, down to Yakima, Washington. The transmission system in this area serves the central Washington towns of Wenatchee, Ellensburg, and Yakima, as well as many outlying communities such as Chelan, Ephrata, and Moses Lake. The total peak area load in the Mid-Columbia area is approximately 800 MW. Customers served within this area include: PacifiCorp, Grant, Chelan, and Douglas County PUD's, and several other smaller customers such as Okanogan PUD.

The primary generation resources which serve the Mid-Columbia area are the five hydroelectric projects at Wells, Rocky Reach, Rock Island, Wanapum, and Priest Rapids. These plants have a combined output capacity of over 4500 MW.

The Mid-Columbia area has been the site of significant wind generation development in recent years. Maintaining reliable load service and accommodating renewable resource development are the primary issues for the Mid-Columbia area.

Projects forecast for this area include:

Mid-Columbia Area Reinforcement

Description:

Sectionalize the Vantage 230 kV bus with two series breakers. Add a second breaker between the Vantage and Wanapum 230 kV buses. Upgrade the Vantage-Midway 230 kV line to higher capacity.

Key Drivers:

- Load service to growing loads in the Mid-Columbia area

Issues Being Addressed:

Load growth in the Mid-Columbia area.

Discussion of Alternatives:

Plan of service and cost estimates are currently under development.

Future Projects:

Future projects for the Mid-Columbia area are currently under study.

Commercial Infrastructure Projects

In the Northwest, there is considerable development of new generating resources by Independent Power Producers (IPP's). These developers need access to transmission in order to move their resources to the load centers. This has led to a need for increased capacity in many portions of the transmission system in order to accommodate these transmission service requests as required by the FERC Open Access Transmission Tariff. This category of Commercial Infrastructure Projects includes transmission reinforcements needed to accommodate long-term firm point-to-point transmission service requests.

Network Open Season

In Spring 2008, BPA is initiating a Network Open Season process (NOS) which will affect the implementation of most projects in the following category. The intent of this process is to ensure priority transmission is built by offering precedent agreements to those parties who want to secure long-term firm capacity on BPA's network transmission system. These parties may include generation developers as well as existing customers. Those who accept the precedent agreements are committed to take transmission service at a specified time and under specified terms. Those not yet ready to sign a precedent agreement will have other opportunities as NOS is expected to be offered at least annually.

Once precedent agreements are signed, BPA proposes to "cluster" those requests to determine how much available transfer capability can be offered and which new transmission facilities, if any, will be required to accommodate the requests. By studying confirmed requests in a "cluster," BPA will be able to more efficiently determine collective system impacts and new facility requirements.

The NOS approach is expected to improve transmission queue management by winnowing out the speculative transmission requests for potential future projects and those who are not yet ready to commit to new resources. BPA's current first-come, first-served queue for network transmission requests has grown to a size that makes it difficult if not impossible to manage. Currently, requests in the queue total about 8,500 megawatts of new capacity. At times, the requests have exceeded 12,000 MW. Speculative requests can make it impossible to evaluate the region's priority transmission needs.

The following areas are impacted by Commercial Infrastructure Projects and the Network Open Season process.

West of McNary

The West of McNary transmission path is located in eastern Oregon near Umatilla, Oregon. The West of Slatt path is located in eastern Oregon, south of the town of Arlington, Oregon. These two paths are in series with each other and represent a major east-west path through BPA's transmission system. This area has been the site of a large amount of generation development over the past decade. Initially, a large amount of combustion turbine generation and more recently renewable resource (wind generation) development has occurred. This has resulted in transmission facilities reaching the limit of their capacity.

With the recent surge in development of renewable resources east of the Cascades, there are presently several long-term firm service requests to the Bonneville Power Administration (BPA) which impact the West of McNary transmission path. In order to accommodate these requests, as required by BPA's Open Access Transmission Tariff (OATT), transmission reinforcements are needed.

West of McNary Generation Integration Project

Description:

Build a new, single circuit, 500 kV line (approximately 75 miles long) from McNary Substation to John Day Substation. This is a Commercial Infrastructure Project. The project schedule depends on the outcome of BPA's Network Open Season (NOS) process. If a decision is made to launch the project, the energization date is expected to be approximately 3-4 years after initiating the project.

Key Drivers:

- Point to Point (PTP) Transmission Service Requests
- Interconnection of new renewable resources (wind generation) east of John Day
- Congestion Relief
- System Reliability

Issues Being Addressed:

This project addresses the issue of meeting the FERC Open Access requirements by building the necessary transmission facilities to accommodate new generation resources seeking access to BPA's transmission network.

Discussion of Alternatives:

Other alternatives considered, included:
- McNary-Big Eddy 500 kV line
- McNary-John Day 500 kV and John Day-Big Eddy No.3 500 kV lines
- McNary to a new substation (Station Z) which taps the Wautoma-Ostrander 500 kV line

Wautoma-Ostrander Tap (Station Z) to Big Eddy 500 kV

Description:

Build a new, single circuit 500 kV line (approximately 28 miles long) from Big Eddy Substation to a new substation (Station Z) built near tower 73/1 on the Wautoma-Ostrander 500 kV line. This is a Commercial Infrastructure Project. The project schedule depends on the outcome of BPA's Network Open Season (NOS) process. If a decision is made to launch the project, the energization date is expected to be approximately 4-5 years after initiating the project.

Key Drivers:

- Point to Point (PTP) Transmission Service Requests
- Interconnection of new renewable resources (wind generation) east of John Day
- Congestion Relief
- Load Service
- System Reliability

Issues Being Addressed:

This project addresses the issue of meeting the FERC Open Access requirements by building the necessary transmission facilities to accommodate new generation resources seeking access to BPA's transmission network. The project also addresses the issue of increased reliability to loads in the southwest Washington and Willamette Valley vicinity.

Discussion of Alternatives:

Other alternatives considered, included:

- John Day-Big Eddy No.3 500 kV and Big Eddy-Station Z 500 kV lines
- John Day-Station Z 500 kV and Big Eddy-Station Z 500 kV lines
- McNary-Station Z 500 kV line

I-5 Corridor

The I-5 Corridor transmission system extends from the Canadian to the California border and west of the Cascades Mountain Range. However, the present area of concern is the portion of the path which extends roughly from Chehalis, Washington, to Oregon City, Oregon.

With the recent development of new resources along the I-5 Corridor, congestion along this path has increased to the point where transmission facilities no longer have adequate capacity to accommodate the growing demands. There are presently several long-term firm service requests to the Bonneville Power Administration (BPA) which impact the I-5 Corridor transmission system. In order to accommodate these requests, as required by BPA's Open Access Transmission Tariff (OATT), additional transmission reinforcements are needed for the I-5 Corridor.

I-5 Corridor Reinforcement Project

Description:

Construct a new 500 kV line (approximately 70 miles) between southwest Washington (in the vicinity of Castle Rock, WA) and northwest Oregon (alternatives of Troutdale or Pearl are being considered). This is a Commercial Infrastructure Project. The project schedule depends on the outcome of BPA's Network Open Season (NOS) process. If a decision is made to launch the project, the energization date is expected to be approximately 6 years after initiating the project.

Key Drivers:

- Point to Point (PTP) Transmission Service Requests
- Interconnection of new resources along the I-5 Corridor
- Congestion Relief
- Improved service to a major load center
- System Reliability

Issues Being Addressed:

This project addresses the issue of meeting the FERC Open Access requirements by building the necessary transmission facilities to accommodate new generation resources seeking access to BPA's transmission network. The project also addresses the issue of increased reliability to loads in the southwest Washington and Willamette Valley vicinity.

Discussion of Alternatives:

Other alternatives considered, included:

- Sub-grid reinforcements to the lower-voltage system
- New 500 kV line from a new substation in the vicinity of Castle Rock, WA to Troutdale Substation
- New 500 kV line from a new substation in the vicinity of Castle Rock, WA to Pearl Substation

California-Oregon Intertie (COI)

The California – Oregon Intertie (COI) is a multiple owner path that includes a network of 500 kV AC transmission facilities that connects the Pacific Northwest (PNW) with Northern California. Owners include the Bonneville Power Administration (BPA), PacifiCorp (PAC), and Portland General Electric (PGE) at the northern end, and Pacific Gas & Electric (PG&E), Western Area Power Administration (WAPA), and Transmission Agency of Northern California (TANC) at the southern end.

In order to accommodate the long-term firm transmission service requests, as required by BPA's Open Access Transmission Tariff (OATT), additional transmission reinforcements are needed for the COI. The plan of service consists of the following:

COI 4800 MW Reinforcement Project

Description:

The COI Reinforcement project consists of the following upgrades and additions:

- Install new series capacitors at Bakeoven Substation along the John Day – Grizzly #1 and #2 500 kV lines, along with required control, protection, and communication equipment.
- Install two new 200 MVAR shunt capacitor groups at Captain Jack 500 kV Substation.
- Install one new 300 MVAR shunt capacitor group at Slatt 500 kV Substation.
- Upgrade the John Day-Grizzly 500 kV lines Nos. 1 and 2

The project schedule is contingent on agreements with the other COI owners. Once the necessary agreements are in place, it would be approximately 3 years until the project is energized.

Key Drivers:

- Point to Point (PTP) Transmission Service Requests
- Congestion Relief
- System Reliability

Issues Being Addressed:

This project addresses the issue of meeting the FERC Open Access requirements by building the necessary transmission facilities to accommodate new generation resources seeking access to BPA's transmission network.

Discussion of Alternatives:

Other sites for the location of series and shunt compensation were considered as alternatives for this project.

On-Going Projects

NERC Criteria Compliance

Description:

This is a general category for grid expansion projects that are required in order to comply with mandatory NERC Reliability Standards. This category may include projects such as line upgrades, line or transformer additions, bus sectionalizing breaker additions, etc.

Key Drivers:

- Mandatory compliance with NERC Reliability Standards

Issues Being Addressed:

- NERC Compliance

Discussion of Alternatives:

A discussion of alternatives will be included on a case by case basis once the individual projects are identified.

Main Grid Reactive Additions

Description:

General category for reactive additions required to support voltage schedules system wide.

Key Drivers:

- Reliability Standards for system voltages
- Load Growth

Issues Being Addressed:

- Voltage Support

Discussion of Alternatives:

A discussion of alternatives will be included on a case by case basis once the individual projects are identified.

Line Relocations on Tribal Lands

Description:

BPA has a number of facilities which cross tribal lands. As BPA's rights to cross these lands expire, they must either be re-negotiated or the lines must be physically re-located. This general category covers the funds needed to rebuild the lines off of the tribal lands if new rights cannot be negotiated.

Key Drivers:

- Expiring agreements with the tribes for right-of-way access

Issues Being Addressed:

Tribal agreements and right-of-way access for transmission facilities.

Discussion of Alternatives:

This category covers all feasible alternatives for securing access to right-of-ways.

Main Grid Facility Additions

Description:

This is a general category for grid expansion projects required to support customer needs or other contractual obligations or criteria. This category may include projects such as line taps, substation bay additions, redundant transfer trip addition, or remedial action schemes.

Key Drivers:

- Contractual Obligations
- Customer service requirements
- Criteria Compliance

Issues Being Addressed:

Same as Key Drivers, above.

Discussion of Alternatives:

A discussion of alternatives will be included on a case by case basis once the individual projects are identified.

Other Associated Interconnection Facilities

Description:

This is a general category for grid expansion projects required to interconnect new resources, or customer lines and loads, into the transmission system, as required by BPA's Open Access Transmission Tariff (OATT). This category may include projects such as line upgrades, new lines, new substations, etc.

Key Drivers:

- Generation Interconnection
- Lines and Loads Interconnection
- Contractual Obligations

Issues Being Addressed

Same as Key Drivers above.

Discussion of Alternatives

A discussion of alternatives will be included on a case by case basis once the individual projects are identified.

Network Open Season Additions

Description:

This is a general category for grid expansion projects required to support BPA's Network Open Season process and accommodate long term firm transmission service contracts. This category may include projects such as line upgrades, new transmission lines, new substations, series compensation, etc.

Key Drivers:

- Point to Point (PTP) Transmission Service Requests
- Contractual Obligations

Issues Being Addressed:

Same as Key Drivers, above.

Discussion of Alternatives:

A discussion of alternatives will be included on a case by case basis once the individual projects are identified.

Area and Customer Service

The Area and Customer Service asset group consists of facilities, typically 230 kV and below, which function primarily to serve area and customer loads. BPA has over 9000 circuit miles of line in this category. This network serves load areas across Oregon, Washington, Idaho, and Montana. Typical area and customer loads are served either radially or by a loop network. Typical projects in this category, include line taps, new substation development, transformation, and reactive additions. These projects are usually driven by load growth and contractual obligations to serve the load.

Some of the key drivers for expansion of Area and Customer service facilities, include:

- Load Service/Load Growth
- Compliance with mandatory Reliability Standards
- Contractual Obligations
- Improved Operational and Maintenance Flexibility

Area and Customer Service Projects

Area and Customer Service Projects typically share a common key driver of load service. These projects can be divided into sub-categories based on their geographic location within the system.

South Oregon Coast

Rogue SVC (Static VAR Compensator)

Description:

Install a 115 kV Static VAR Compensator (SVC) at Rogue Substation with a dynamic range of -45 MVAR to +50 MVAR.

Key Drivers:

- Maintain reliable load service to the South Oregon Coast load area

Issues Being Addressed:

Load growth along the South Oregon Coast

Discussion of Alternatives:

Other alternatives to the project included adding shunt capacitors in the area or building new transmission into the area. Shunt capacitors did not offer adequate fine-tuning of voltage control and building new transmission was not economically feasible at this time.

Lebanon Area

Lebanon Shunt Capacitor Addition

Description:

Add a 19.6 MVAR, 115 kV shunt capacitor bank at Lebanon Substation

Key Drivers:

- Voltage support to maintain reliable load service to customers

Issues Being Addressed:

Maintain reliable service to loads in the Lebanon area

Discussion of Alternatives:

Another alternative considered was adding a new 230/115 kV transformer in the Lebanon area. However, it was determined that this more costly project could be deferred with the shunt capacitor addition.

City of Centralia

City of Centralia Reinforcement

Description:

Rebuild both of the Chehalis-Centralia 69 kV lines No.1 and 2 with higher capacity conductor using H-frame structures, and 115 kV spacing and insulation. The lines will be operated initially at 69 kV.

Key Drivers:

- Load service obligations
- Commercial and Industrial load growth in this area

Issues Being Addressed

Maintain reliable service to growing loads in the Centralia vicinity.

Discussion of Alternatives

Other alternatives considered for this project included building a new double circuit 115 kV line. However, the upgrade was selected as the preferred alternative because it was the most cost effective solution to provide adequate capacity for load service.

Southern Idaho and Lower Valley Area

Lower Valley Reinforcement (Hooper Springs)

Description:

This project was originally a joint project between BPA, PacifiCorp, and Lower Valley Energy. Each utility's component of the project is described below.

(BPA portion): Construct Hooper Springs Substation. Install a 138/115 kV transformer at Hooper Springs.

(PacifiCorp portion): Construct three mile knoll Substation. Install a 345/138 kV transformer. Loop in the Goshen-Bridger 345 kV transmission line.

(Lower Valley Energy portion): Build a new 20 mile, double circuit line, from Hooper Springs to Lanes Creek/Valley. The new double circuit line will be built as 161 kV, but operated initially at 115 kV. The project cost and schedule is contingent on agreements being signed between the affected parties.

Key Drivers:

- Voltage Stability
- Reliable load service to the Lower Valley and Fall River Load Areas

Issues Being Addressed:

Maintaining reliable load service to the Lower Valley and Fall River area loads.

Discussion of Alternatives:

- Build a new 115 kV Substation (Lanes Creek) with a 115/161 kV transformer bank. Add a 161-kV terminal at Goshen. Build a new 161 kV line (approx. 65 miles) from Lanes Creek to Goshen.
- Add two 161 kV terminals at Goshen Substation. Add a new 161 kV yard at Swan Valley Substation. Add a 115/161 kV transformer at Palisades. Rebuild Palisades-Goshen as a 161 kV double circuit line. One circuit would become the Goshen-Swan Valley No.2 161 kV line and the other would become the Goshen-Palisades 161 kV line.
- Same as the previous option except the Goshen-Swan Valley line would be operated as 161 kV, but the Goshen-Palisades line would be initially operated at 115 kV.

Drummond Shunt Capacitor Addition

Description:

Add two groups of 115 kV shunt capacitors (15 MVAR each) at Drummond Substation

Key Drivers:

- Voltage support for reliable load service to customers

Issues Being Addressed:

Maintaining reliable load service to customers in the Southern Idaho load service area

Discussion of Alternatives:

Alternate locations for the shunt capacitor addition were considered but Drummond was chosen to provide optimal voltage support to the area.

On-Going Projects

Area Service Reactive Additions

Description:

This is a general category for reactive additions to support voltage schedules system wide for the Area and Customer Service asset category.

Key Drivers:

- Reliability Standards for system voltages
- Load Growth

Issues Being Addressed:

Voltage Support

Discussion of Alternatives:

A discussion of alternatives will be included on a case by case basis once the individual projects are identified.

Customer Service Facility Additions

Description:

This is a general category to capture facility additions or upgrades required to meet customer service needs defined by contractual obligations. Projects in this category may include substation bay additions, line upgrades, line taps, etc.

Key Drivers:

- Customer service contractual obligations

Issues Being Addressed:

Same as Key Drivers, above.

Discussion of Alternatives:

A discussion of alternatives will be included on a case by case basis once the individual projects are identified.

Upgrades and Additions

This category consists of additions to high voltage equipment or control/communications equipment or replacement of existing facilities with new facilities that have additional capacity or capabilities. Some examples of projects in this category include: adding high voltage switchgear at a new tap point, upgrading a transmission line with higher capacity conductor, or replacing obsolete control systems.

Some of the issues associated with this category are:

- Land availability for additions (either lines, substations, or communications)
- New technology for potential upgrades – proven or experimental
- Capacity needs versus cost for upgrades

Some of the key drivers for upgrades and additions are:

- Compliance with mandatory NERC Reliability Standards
- Aging infrastructure – poor condition of existing facilities
- Lack of manufacturer support
- Lack of spare parts
- Obsolete technology (no longer compatible with other equipment on the system)
- Cost of maintaining existing equipment versus service life from upgrading equipment.

Upgrades and Additions Projects

Albany-Eugene 115 kV Line Rebuild

Description:

Rebuild a section of the Albany-Eugene 115 kV line with new structures and higher capacity conductor

Key Drivers:

- Aging and poor condition of existing structures
- Load growth

- Compliance with NERC Reliability Criteria

Issues Being Addressed:

Same as Key Drivers, above.

Discussion of Alternatives:

The plan of service for the project is currently under development.

Tucannon-Walla Walla 115 kV Line Rebuild

Description:

Rebuild the Tucannon-Walla Walla 115 kV line section with new structures and higher capacity conductor.

Key Drivers:

- Aging and poor condition of existing transmission structures

Issues Being Addressed:

Same as Key Drivers, above.

Discussion of Alternatives:

The plan of service for the project is currently under development.

PDCI (Pacific DC Intertie) Upgrade

Description:

The primary focus of the Celilo upgrades is on Converter 1 and 2. Most of the existing facilities are 25+ years old and in many cases the equipment is completely obsolete in terms of vendor support and spare parts. Upgrades of the Control/Protection systems, DC filters, AC filters, Cooling Systems, Valves and Buswork will address age/condition related issues as well as support potential capacity expansion. The upgrades will improve NERC compliance with system protection and control requirements for reliability.

Converter 3 and 4 work is predominantly to maintain existing capability and is covered in the Sustain Portfolio in this report under the Stations Replacement section.

Key Drivers:

- Control System – Expandability
- Aging equipment
- Reliable Operation of the PDCI
- Revenue

Transformer Spares

Description:

Purchase 5 new transformers that will be designated as system spares. In 2006-2007 we saw the failure of 6 large power transformers and 2 reactors. The spares will primarily replace the spare transformer capacity that was put into service after the failures. A revised spare transformer policy is being implemented that will relocate both existing and new spare transformers to strategically locate spares in line with system critical infrastructure. These spares will be installed at Ponderosa, Monroe, Sickler, Hot Springs, and Alvey substations.

Key Drivers:

- Reliability
- Aging equipment
- Environment

Issues Being Addressed:

Replace transformer spares due to system failures and relocate new and existing spares to meet reliability priorities.

3.2 SUSTAINING PORTFOLIO

Replacement Capital planning is asset driven. The objective of the sustaining portfolio is to identify near and long-term activities and investments needed for the assets to meet BPA's long-term objectives. The Replacement Capital portfolio consists of Investments required to maintain the overall asset health and therefore, maintain system capacity and performance over the 10-year planning period to meet reliability, availability, environmental, regulatory/legal requirements and safety long term outcomes.

Transmission Services' existing assets are grouped in six major categories:

- Lines
- Station
- System Protection & Control
- Power System Control
- Control Centers
- Tools & Equipment Acquisition Program (TEAP)

Key Drivers

- **Equipment Operability** - In some cases, equipment becomes unable to reliably perform its function to acceptable performance standards. This can be due to design problems, changed usage patterns, changes to other parts of the transmission system, or premature wear out. In most instances, the equipment must be replaced to maintain the reliability of the system.

- **Equipment End-of-life** - The majority of BPA's original transmission assets were installed from the 1940s through the 1980s. As these assets approach their end of life, they require increased maintenance and capital investment to continue to provide reliable transmission service. While age is a factor, actual end-of-life is affected by the equipment's operating environment, its operating history, and application. End-of-life determinations are made based on condition assessments and life cycle costs for maintenance.

- **Obsolescence and Original Equipment Manufacturer (OEM) Support** - Closely related to the age of the equipment, equipment obsolescence and lack of OEM support (in terms of replacement parts and, in some cases, **technical** expertise) can make maintaining certain equipment impractical. Although the equipment may be in fair or good condition, the lack of replacement parts, either in stock or from suppliers, makes repair very expensive or even impossible. This situation can place unacceptable risks on the system since the failure of one of these components could cause extended outages until spare parts can be found, or new equipment can be acquired and installed.

- **Equipment Security and Exposure to Hazards** - NERC has placed an increased focus on security, specifically in relation to critical infrastructure, which includes power systems. This has caused BPA to examine, in detail, both its physical and cyber security standards and procedures. The transmission system is also exposed to seismic risk and severe weather systems. Transmission Service's approach to asset management incorporates risk based methodologies to prioritize and reduce retained risk.

- **Safety** – These factors primarily address operation and maintenance of and within BPA facilities, and while they very definitely can affect the public (i.e. transmission lines and breach of substation fencing) they are predominantly used to protect BPA workers and facilities during routine and emergency work. Various standards and regulations set forth minimum requirements for the safe operation, maintenance, and handling of electrical transmission facilities and supporting infrastructure. To name a few these include NEPA for handling of hazardous materials, OSHA and NESC for both safe operation and maintenance of electrical facilities. In addition, there are standards addressing climbing of towers, poles and structures as well as the licensing, operation, and maintenance of heavy equipment. There are numerous national and international design standards such as IEEE (includes NESC), IEC, ANSI, NEMA, that are the foundation for transmission facility design standards impacting electrical clearances, mechanical loading and stresses, seismic hardening, that all contribute to safe operation and maintenance.

- **Legislative, Regulatory or Contractual Obligations** – These factors primarily address how BPA's operations affects the public including our customers. Various agencies such as OSHA, the Environmental Protection Agency (NEPA), NERC, WECC and FERC, and various state and regional requirements affect how BPA operates and maintains its facilities and how transmission services are provided (open access). Under NEPA equipment containing oil such as transformers, and equipment containing gases such as SodiumHexa-Flouride (SF6), and lead acid station batteries are subject to strict environmental controls regarding release of hazardous substances during operation, maintenance, and decommissioning. Additional environmental requirements set standards for electric field strength and noise levels for the operation of electrical transmission facilities. Some of these requirements will impact the amount of land purchased for facilities, right-of-ways (ROW), access roads, and buffer zones. NERC, WECC, and FERC requirements address primarily system reliability and open access and set forth minimum standards for the operation and maintenance of electrical transmission facilities to maximize system availability and access. Contractual obligations between BPA and customers primarily reflect obligations to meet open access requirements and outline specific responsibilities and ownerships for the customer and transmission provider in regard to costs for interconnection, expansion, or other services (wheeling, voltage control, reactive support, etc.).

3.2.1 Overhead Lines

This Transmission Overhead Line asset plan is based on a comprehensive review and assessment that was completed in 2007 of the overhead asset, including age and health demographics and risk assessment to BPA's business and mission critical success. In addition, the plan will recommend an appropriate investment level to mitigate known or suspected risks to BPA's long term strategic objectives. Aging, for this effort, is defined as the deterioration over time of critical line component's mechanical, electrical, or thermal performance capabilities significantly increasing their risk of failure. Aging also includes critical component obsolescence where it results in the inability to timely respond to component failures threatening line integrity and/or electrical service continuity.

3.2.1.1 Overhead Asset: Overview

The BPA Transmission system consists of about 15,200 circuit miles of high voltage transmission lines suspending about 70,000 miles of cable on 89,560 structures. The power lines are composed of numerous conductor and groundwire cables carried on both lattice and pole structures composed of steel, aluminum, and wood materials. Fiber optic cables are carried by the power line structures carefully located to ensure efficient co-existence of both bulk transfer systems. The preponderance of BPA's overhead asset is contained on the 500 kV primary power delivery grid, and the 230 kV and 115 kV grid serving load and interconnecting generation.

The BPA transmission system was designed and constructed in phases starting in the late 1930's. Over this approximate 70 year time-line the electric utility industry has evolved. This evolution has resulted in a system that was constructed, at different times and voltages, using different materials and industry standards. The BPA system exemplifies this evolution in terms of the age, number, and types of designs that are currently installed. Essentially, the 115 and 230 kV systems were primarily built in the first 30-40 years of BPA's existence and the 500 kV class was built-out over the last 30-40 years.

In assessing the condition of the overhead transmission asset a number of metrics are being used to base an evaluation including installed age, physical condition, obsolescence of components, estimated remaining service life, and operational impacts to the reliability and availability of the asset for BPA's mission and business success. Excluding operational impacts, all primary metrics carry the common degradation metric of age.

BPA's overhead transmission asset, with an installed investment of $2.2 billion invested dollars, is aging in accumulated years and is broadly spread across BPA's service area. Figure 1.1 below shows the distribution of BPA's transmission lines by kV rating by age groups. Spatially the transmission system has been built in either a large loop connecting the Puget Sound, Willamette valley, and Spokane primary load centers to Eastern generation sources, or intertie connections to either Canada, California, or Montana. Temporally much of the primary loop and significant portions of the Southern intertie exceed 40 years of service.

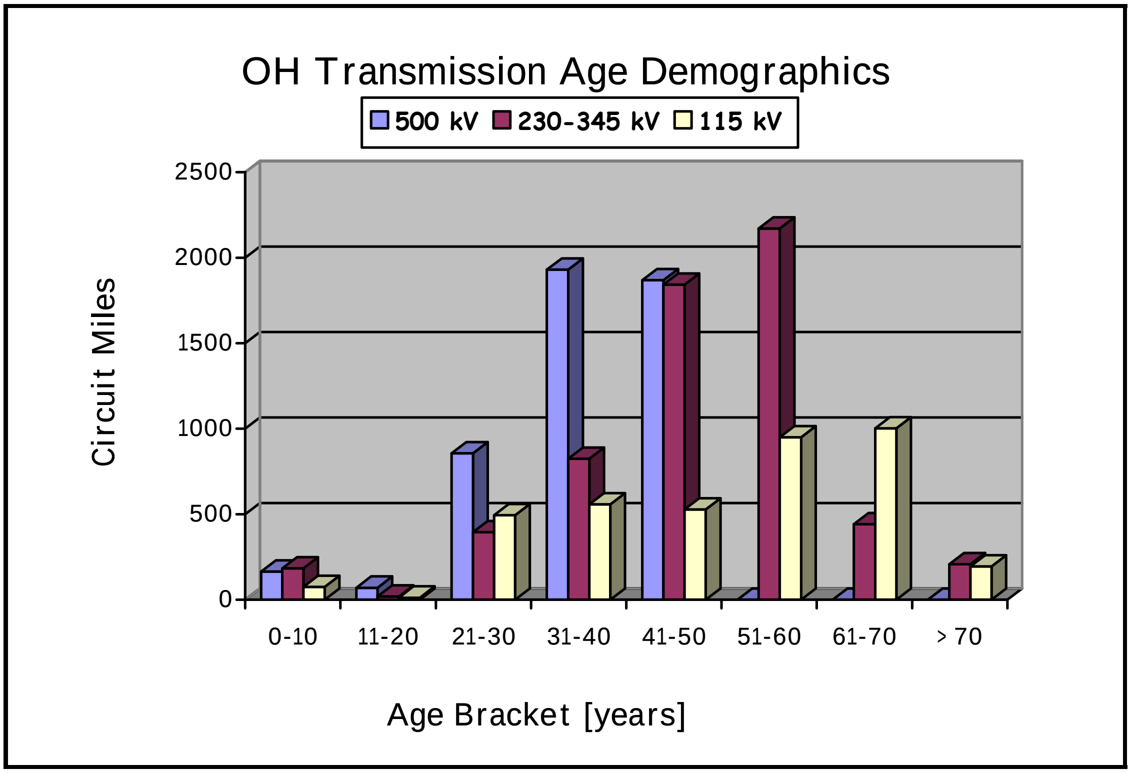

Figure 1.1: Transmission System Age Demographics by Voltage

3.2.1.2 Overhead Asset: Health Demographics and Assessment

The overhead asset is a vast and complex physical and electrical system when examined as an aggregate, and hence is truly difficult to characterize as an overall entity. In order to build a quantitative evaluation of the assets overall health, the transmission system was separated into major components organized by common age related attributes.

It is reasonable to anticipate that major line components will age at different rates necessitating risk management and assessment strategies tailored to the characteristics of each major line component. Hence, the major critical line components are grouped and identified as populations which facilitate efficient health assessment and risk management organization dependent on 1) their criticality to line performance, 2) aging related characteristics, 3) concerns for obsolescence, and 4) sub-component connectivity.

This Overhead Transmission asset plan has identified twelve major critical line component categories organized utilizing the four basic criteria discussed above and listed in Table 1.1

Overall Component Health Demographics											
	Major Component	Physical Condition			Obsolescence			Remaining Life			Asset Health
		Good	Fair	Poor	Good	Fair	Poor	> 20	10-20	< 10	
Passive	Conductors										Good
Passive	Towers										Good
Passive	Fiber Cables										Fine
Passive	Tower Footings										Fine
Passive	Guys										Fine
Passive	Counterpoise										Fine
Active	Connectors										Impaired
Active	Insulators										Impaired
Active	Dampers										Impaired
Active	Wood Poles										Impaired
Active	Spacers										Poor
Active	Airway Warning										Poor

Table 1.1: Component Health Demographics

Since all the components on BPA's overhead transmission system have essentially the same relative age, those components which are more passive and do not routinely accumulate loading cycles over time tend to exhibit better asset health than those components which are active and accumulate regular loading cycles as they age.

Conductors, towers, fiber optic cables, tower footings, guys, and counterpoise are more passive and do not accumulate daily loading cycles. In contrast, spacers, dampers, and connectors have continual daily loading cycles forcing degradation as the components age. Wood poles also have daily duty cycles as wood naturally degrades with age and insulators, being located in a high electric field, sacrifice galvanizing at an accelerated rate. Therefore, as the Active components accumulate service years they also accumulate numerous loading cycles exhibiting poor health demographics long before the Passive components of the overhead transmission asset. Hence, replacement programs will typically need to be developed for the Active line components, while the Passive line components with proper maintenance will likely survive the entire service life of the specific transmission line on which they are installed.

Another interesting demographic of overhead transmission lines is the relative difference in installed costs between Passive and Active line components. Relative initial costs between the major Passive line components consisting of conductors, towers, guys, and counterpoise and Active line components consisting of connectors, insulators, dampers, and/or spacers are about 94% for Passive components and 6% for Active components.

The primary message from the cost demographics for the aging overhead transmission asset is the Active major line components are relatively small cost items (6%) and yet are either critical to overhead transmission asset health for availability (connectors and insulators) or are protecting the huge investment in the Passive major line components (dampers and spacers). Whether a critical or protective line component, a failing Active component will typically justify a replacement or refurbishment program versus asset retirement as the relative costs are acceptable to return the overall investment to Good asset health. In contrast, if major Passive line components such as the conductors or structures age to Poor asset health, then asset retirement would be a viable option to release the right-of-way for other enhancement options such as rebuild, voltage upgrade, or new route selection.

Based on the asset health demographics of Table 1.1, the TLM health assessment of Significant Equipment lines, observations and investigations from both Engineering staff and TLM working patrols, the overhead transmission present asset health assessment is given the rankings as shown in Figure 1.2

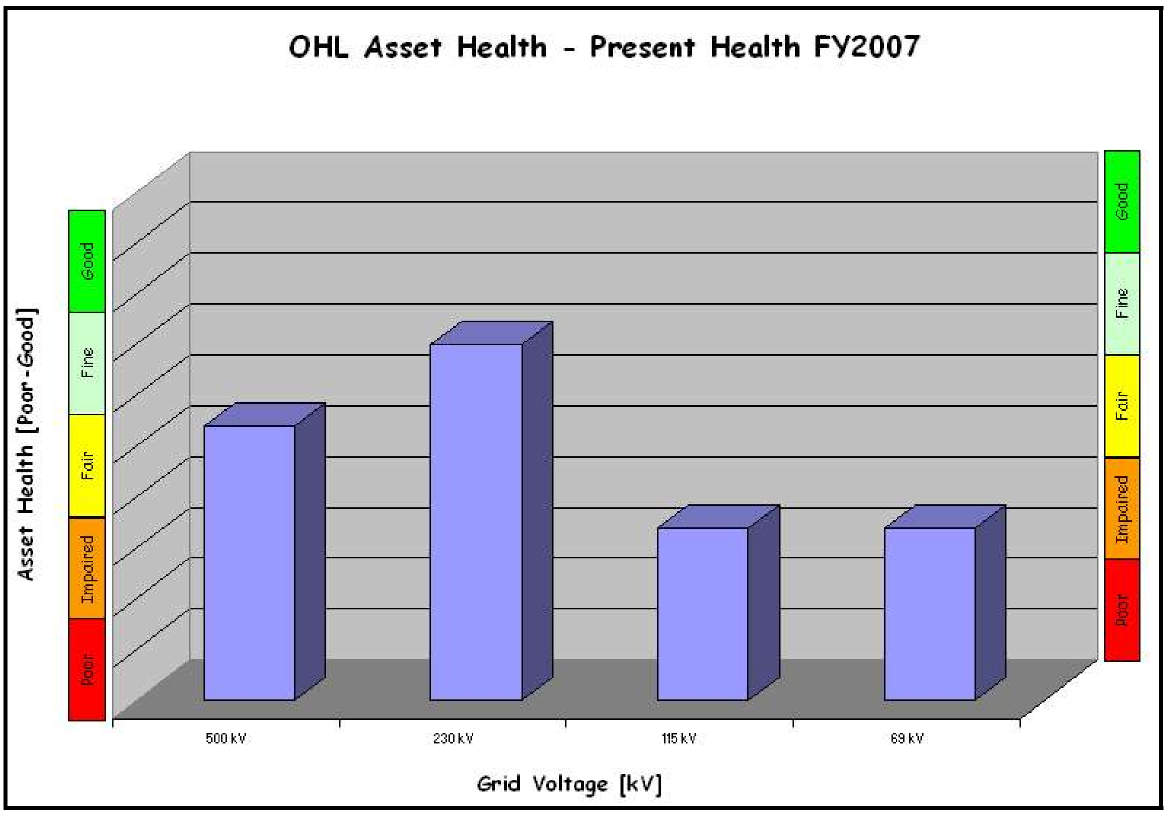

Figure 1.2: Overall Overhead Transmission Asset Health by Voltage

3.2.1.3 Overhead Asset: Risk Assessment to Operating System

Risk assessment is summarized on Figure 1.3 plotting System Impacts against Component Health providing a measure of a component's overall health in terms of physical health, obsolescence, and remaining life against potential operational impacts to system reliability and asset availability. The plot is organized into essentially five regions from High Risk in the upper right corner to Low Risk in the lower left corner.

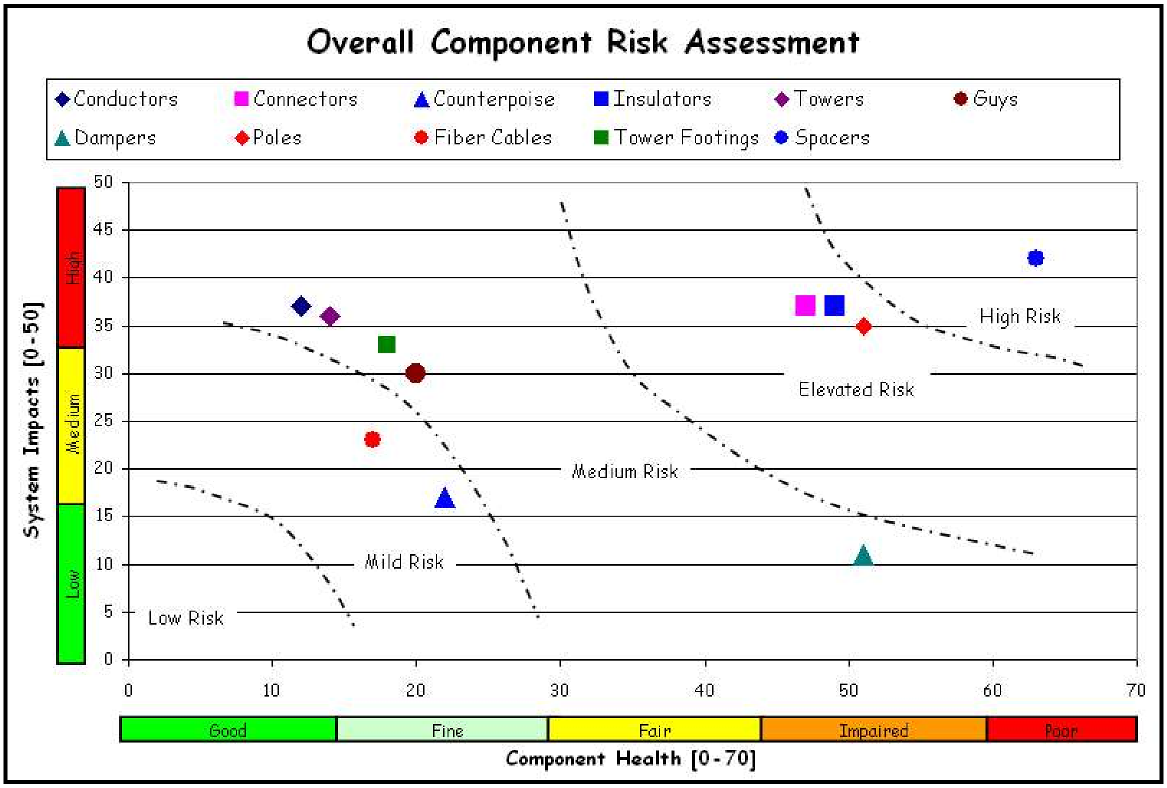

Figure 1.3: Overhead Transmission Asset Component Risk Assessment

3.2.1.4 Emergency Minimum Spares (EMS)

The Transmission Line Maintenance organization maintains portable Lindsay restoration towers which can be quickly and efficiently erected to temporarily replace failed structures. Emergency maintenance spare stocking levels of transmission line hardware, conductor, poles and steel shall provide the ability to restore 1.6 kilometer of failed transmission line at any voltage.

3.2.1.5 Overhead Asset: Recommendations and Future State

Based on the overall health and risk assessment, this overhead asset plan has a number of recommendations for consideration by management. In order to meet Agency and Transmission Services strategic long term outcomes, a characterization of a Future State for all twelve major line components of the overhead asset has resulted in a number of strong inferences which naturally gravitate into recommendations for action. The fundamental goals and drivers for these recommendations are focused on 1) improving the overall health of the installed overhead asset to a Good status to ensure its continued success and 2) provide proactive processes to manage and assess the overhead asset as it continues to age to demographic levels which BPA has little or no experience managing and mitigating. As these goals and drivers are common across the industry both locally and globally, a more proactive strategy and approach requires development in order to have adequate assurance of success. Inadequate or improper management, assessment, or mitigation processes inconsistent with the new challenges of a significantly aged overhead asset can easily result in gross loss of reliability and/or availability threatening the very mission and business success of BPA and its stewardship of the Region it serves.

The sixteen recommendations essentially fall into four groupings addressing the goals and drivers discussed above. The groupings are;

- Aggressively complete and retire the active replacement programs to bring the overall asset health into a Fine ranking.
- Pursue expanding the replacement and/or refurbishment efforts to include four additional efforts to bring the overall asset health into a Good ranking.
- Aggressively continue to characterize and assess the overhead asset at an adequately granular level both temporarily and spatially to facilitate proper proactive management.
- Continue to develop and improve documented strategies to better manage and mitigate the adverse effects of aging, or age related degradation processes, in a manner which ensures the continued success of the reliability and availability of the overhead asset.

There are many inconsistencies and inadequacies with present processes and demographic data and using a reactive strategy using minimal quality data, which has served BPA in the past, will be grossly inadequate as the asset ages into the future. Additionally, the amount of mechanical faults, systemic deficiencies, and age related degradation, when aggregated are sufficient to cause genuine concern for the overall reliability and availability of the installed overhead asset.

3.2.1.5a Future State: Improve Transmission Asset Health to Good Ranking with Four New Replacement Programs

In Figure 1.5 below, the blue bars represent the current over-all asset condition, the purple bars represent the expected asset condition upon completion of the current active replacement programs, and the yellow bars represent the expected asset condition upon completion of the four additionally identified replacement programs.

The four additional replacement programs are recommended to further increase the overall transmission asset health ranking from Fine to Good. These future Replacement and Refurbishment Programs are predicted to generally improve the overall asset health for the overhead transmission asset to a Good ranking as shown on Figure 1.5.

As with the present replacement programs, the active major components of the overhead transmission asset are the best opportunity to increase the overall asset health of the overhead transmission system. Similar replacement or refurbishment programs are recommended for the following:

- Connectors
- Insulators
- Dampers

These components are predicted to have Impaired to Poor asset health and represent an obvious risk to the reliability and availability of the overhead transmission asset.

The final replacement program being recommended for consideration involves the damaged fiber optic cables on a limited number of lattice steel towers.

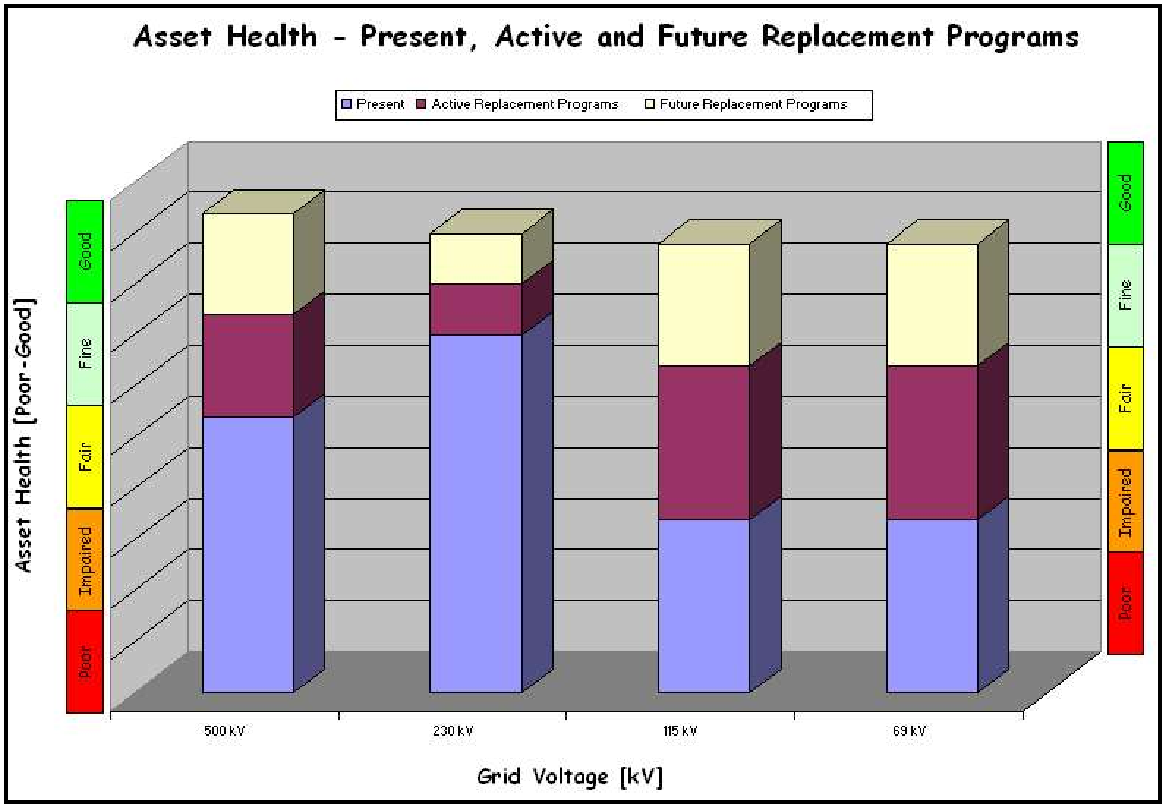

Figure 1.5: Overall Transmission Asset Health With Completion of Recommended Replacement Programs

3.2.1.5b Future State: Records, Processes, and Information Repositories for Overhead Asset Management, Health Assessment, and Measurement Metrics

One important recommendation is to continue the effort to populate the Transmission Line Design Data (TLDD) database with adequate physical transmission design information to robustly characterize the overhead asset

Another important recommendation identifies the need to either enhance Transmission Line Maintenance Applications database (TLM Apps) to robustly retain line component asset health data, or develop a data repository which would provide equivalent functionality. Again, to properly manage, assess, and analyze the overhead transmission asset it must be adequately field inspected, and the collected component health assessment data must be retained in a well defined manner and location, to support component health assessment. Presently, the only major line component which is assessed and retained with reasonable processes to provide comprehensive health assessment analysis are wood poles. This recommendation would substantially enhance and/or replace TLM Apps to provide similar capability for retaining adequate asset health assessment data for all the major line components on the overhead transmission system.

Finally, a third recommendation calls for the development of comprehensive metrics to both collect and retain asset health assessment data on a regularly defined schedule in a consistent, reliable, and comprehensive manner. The collection and retention of health assessment data in a standard manner and format, on a regularly well defined schedule, will provide tremendous value to 1) assist in identifying aging trends, 2) provide justification and timing of replacement programs, 3) facilitate proper management of line component populations over time, and 4) assist in predicting remaining service life.

3.2.1.5c Future State: Develop Strategies to Monitor, Better Assess, and Analyze Overhead Asset Health for Proper Management of an Aging System

There is a need to develop monitoring and assessment analysis strategies to better manage and characterize the overhead asset as it continues to age in manners still unknown and poorly understood. As this challenge is common in the industry, opportunities will continue to become available to further expand those strategies and sophistication levels of modeling by participating and partnering with other utilities and organizations.

By developing these strategies now, strengths and weaknesses can be identified with these comprehensive and documented plans to better leverage what is understood for better asset management today, plus actively seek more clarity and understanding for better models and management tools tomorrow. Only by approaching this new territory concerning component aging with a “road map”, a clear understanding as to what will bring value, and the knowledge of what is not known can BPA hope to mature processes and practices which provide proper and adequate management of the overhead transmission asset as it continues to age.

The resource requirements needed to move this strategy forward is yet to be determined, as the workload to collect the identified data is unknown at this time. As the processes and procedures are developed to collect the identified data through FY09-11, we should be able to adequately determine resource requirements to successfully implement these data improvement recommendations.

3.2.1.6 Active Overhead Asset Replacement Programs

Spacer Replacement Program

Description:

Extend the life of overhead transmission lines through replacement of components that have reached end of life, have degraded functionally, or have a class defect related to that specific component.

Key Drivers:

Equipment end-of-life

Issues Being Addressed:

Threat to the overhead 500 kV grid due to failing spacers and spacer-dampers (spacers) used on all bundle conductors. As the spacers reach end-of-life their failure mode can involve disassembly which usually results in collateral damage to the conductors they were originally intended to protect. Additionally, the spacer-dampers also mitigate fatigue damage to conductor aluminum strands, and with their failure such vibration protect is lost exposing the conductors to irreversible damage which would significantly accelerate the conductors aging process.

Program Management:

This is a recurring program which began in 2000 with a predicted sunset of about FY2017. The Spacer Replacement Program, starting in FY2006, was greatly expanded to increase the replacement rate from 6,000 units per year to a target 26,500 units per year.

The projects within this program will be prioritized using a circuit importance ranking criteria and availability of scheduled outages. Transmission is presently preparing a list of all overhead circuits and is ranking them in order of importance to the system.

Airway Lighting Replacement Program

Description:

Replace airway lights on the overhead transmission system which have reached end-of-life due to age and obsolescence plus are not presently FAA compliant. Additionally, the cost to repair, when parts are available, exceeds the replacement costs using present industry standard designs.

Key Drivers:

Equipment end-of-life and obsolescence.

Regulatory compliance with FAA standards.

Issues Being Addressed:

The airway lighting neon code beacons and neon waist lights are presently not in compliance with FAA regulations.

Program Management:

An Airway Lighting Replacement Program has been assembled to replace these beacons over the next five years.

Wood Pole Replacement Program

Description:

Retire the wood pole end-of-life replacement backlog of approximately 26,000 poles over the next 10-14 years. This backlog population of wood poles exceeds present Transmission in-house resources to retire on the desired time line to ensure proper management of the overhead asset to ensure reliability and availability.

Key Drivers:

Equipment end-of-life and system reliability.

Issues Being Addressed:

Primary issues include ensuring the reliability and availability of the overhead asset for mission and business success. Additional issues include the size of the replace backlog continuing to age and the limited in-house resources available to service the threat.

Program Management:

This is a recurring program with a predicted sunset of about FY2017-FY2021.

The projects within this program will be prioritized using a circuit importance ranking criteria and availability of scheduled outages. Transmission is presently preparing a list of all overhead circuits and is ranking them in order of importance to the system. Additionally, Transmission is formulating a strategy to achieve a retirement sunset on a 10 year aggressive replacement program.

3.2.1.7 Overhead Life Extension Replacement Programs

Connector Replacement/Refurbishment Program

Description:

Extend the life of overhead transmission lines through replacement or refurbishment of components that have reached end of life, have degraded functionally, or have a class defect related to that specific component.

Key Drivers:

Equipment end-of-life

Issues Being Addressed:

Threat to the overhead 500 kV grid due to failing connectors on bundle jumpers carried by about 370 deadend towers. This is a systemic issue with a legacy design which has been retired in the 1980's but is still carried by a number of towers on the 500 kV grid. As the jumpers age to failure their failure mode threatens the reliability of the line as the resultant collateral damage is often extensive.

Program Management:

This is a new program which will be further scoped and assembled in FY08 with a predicted start date of FY2009 and a sunset of about FY2012.

The projects within this program will be prioritized using a circuit importance ranking criteria and availability of scheduled outages. Transmission is presently preparing a list of all overhead circuits and is ranking them in order of importance to the system.

Insulator Replacement Program

Description:

Extend the life of overhead transmission lines through replacement of components that have reached end of life, have degraded functionally, or have a class defect related to that specific component.

Key Drivers:

Equipment end-of-life

Issues Being Addressed:

Threat to the overhead asset due to failing insulators on a number of overhead transmission lines. This is a limited systemic issue which is related to age, environmental exposure (typically coast and industrial areas), and corona stress with some designs and higher elevations. As the insulators continue to age they loose the ability to both insulate the conductor from and mechanically attach the conductor to its supporting structure. The result of insulator failure is a sustained loss of the line until repairs can be accomplished.

Program Management:

This is a new program which will be further scoped and assembled in FY08 with a predicted start date of FY2009 and a sunset to be determined.

The projects within this program will be prioritized using a circuit importance ranking criteria and availability of scheduled outages. Transmission is presently preparing a list of all overhead circuits and is ranking them in order of importance to the system.

Damper Replacement Program

Description:

Extend the life of overhead transmission lines through replacement of components that have reached end of life, have degraded functionally, or have a class defect related to that specific component.

Key Drivers:

Equipment end-of-life

Issues Being Addressed:

Threat to the overhead asset due to failing dampers on a number of overhead transmission lines which carry large single conductors. This is a limited systemic issue which is related to age, environmental exposure (open windy terrain), and conductor size. As the dampers continue to age they loose the ability to protect the conductor strands from fatigue damage due to aeolian vibration. Once a damper is failed it does not present an immediate threat to the availability of the transmission line, but exposes the conductor to fatigue damage which significantly accelerates the conductors aging process. Premature aging of the conductor can easily result in extensive conductor replacement at tremendously higher costs than damper replacement.

Program Management:

This is a new program which will be further scoped and assembled in FY08 with a predicted start date of FY2009 and a sunset to be determined.

The projects within this program will be prioritized using a circuit importance ranking criteria and availability of scheduled outages. Transmission is presently preparing a list of all overhead circuits and is ranking them in order of importance to the system.

Fiber Optic Cable Repair Program

Description:

Extend the life of overhead transmission lines through replacement of components that have reached end of life, have degraded functionally, or have a class defect related to that specific component.

Key Drivers:

Equipment accelerated aging due to accumulated abrasion damage on a limited number of fiber optic cable attachment locations.

Issues Being Addressed:

A defective ADSS fiber cable design, which has been retired, still remains unmitigated on a limited number of lattice steel transmission towers. The identified threat to the ADSS fiber system carrying the defective suspension attachment designs need to be retired. In order to realize this retirement goal, finalizing an adequate design and developing and deploying an implementation strategy is required. Once accomplished the overall condition assessment of the fiber optic cable population would then move from Fine to Good, which is the desired condition assessment level of the fiber optic cable communication system. This assessment level is critical as BPA becomes ever more dependent on fiber communication bandwidth, reliability, and availability for operational excellence.

Program Management:

This is a new program which will be further scoped and assembled in FY08 with a predicted start date of FY09 and a sunset to be determined.

The projects within this program will be prioritized using a circuit importance ranking criteria and availability of scheduled outages. Transmission is presently preparing a list of all overhead circuits and is ranking them in order of importance to the system.

3.2.2 Substations

3.2.2.2 Substation Asset: Overview

Substation Assets consist predominantly of high voltage electrical outdoor substation equipment but also includes numerous lower voltage support and auxiliary equipment. For the purpose of evaluating substation equipment health the Assets can be combined into five major equipment groups that are defined by common attributes such as design and materials, application or function, common degradation factors, and common condition measurement tools. The five major equipment groups are further defined by thirteen subcategories in order to identify specific assets that are being proposed for replacement in this report. The subcategories are listed in Table 2.2.

The following paragraphs describe, in general terms, the equipment and associated function of the five major substation asset groups.

***Wirewound Equipment**:*

Includes power transformers, station service transformers, instrument transformers; and series and shunt reactors. These are used for voltage or current transformation, current limiting, fault reduction, and voltage control. There are approximately 630 power transformers and 80 of these are spares. In addition to the power transformers are roughly 260 Load Tap changers. The system contains roughly 500 inductors, referred to as reactors, both oil filled (95) and air core (390). There are roughly 6400 instrument transformers in service on the BPA system, of these approximately 2700 are current transformers and 3700 voltage transformers. The units range from a small 15 kV class solid insulated VT's to 500 kV oil insulated porcelain enclosed CT’s. The system has roughly 750 station service transformers, 55 grounding transformers, and 5 voltage regulators. BPA’s strategy for transformers is to extend the effective life and defer replacement as long as possible while still maintaining a satisfactory level of service.

Switchgear:

Includes all breakers, circuit switchers, disconnect switches, and fuses used to protect, isolate, and sectionalize other substation equipment or transmission lines. Also included under Switchgear are the three GIS facilities whose design (SF6 Gas insulated) and maintenance aspects are very similar to that of circuit breakers. The BPA transmission system employs approximately 1,800 circuit breakers made up of a variety of different equipment in terms of voltage classes (from 15 kV up to 500 kV);

arc extinguishing medium (airblast, vacuum, minimum or bulk oil, SF6 gas); insulation types (live tank, dead tank or gas insulated-GIS); and numerous vintages and brands. Ages range from newly replaced to 65 years, with an average age of 19 years. There are approximately 240 circuit switcher and load break switcher type devices ranging 69 kV up to 500 kV and utilizing arc extinguishing medium of either vacuum or SF6 gas. Circuit switchers range in age from newly installed to forty-five years. This asset group also includes BPA's three Gas Insulated substations (Taft & Buckley – 500kV and Ponderosa – 230kV) due to similarities in design criteria and maintenance practices.

There are approximately 6,600 high voltage disconnect switches on the BPA transmission system from 15kV to 500kV. Disconnect switches are used to isolate other electrical equipment. They provide the visible air gap required by OSHA, Oregon and Washington State Department of Labor & Industries so that other electrical equipment can be safely maintained. There are approximately 3,100 fuses ranging from 15kV up to 115kV protecting both instrument transformers and power transformers.

Capacitors:

The BPA system employs approximately 130 shunt capacitor groups comprised of approximately 350 sections ranging from 15kV to 500kV, and are of both the fused and fuseless type. Because capacitor sections can be independently switched and replaced it is more accurate to track sections rather than groups both for replacement purposes and for maintenance resources. Shunt capacitor sections range from newly installed to 50+ years with the average and median ages being 13 and 11 years respectively.

BPA's 18 Series Capacitors were installed during two major 500kV transmission capacity upgrade projects. The 3rd AC Intertie Project added 8 Series Capacitors at five different stations and these are approximately 14-15years old. The Eastern Washington Reinforcement project added 10 more series caps to the system for additional transmission capacity and these are 4-5 years old. While the Slatt Thyristor Controlled Series Capacitor (TCSC) is for the most part also a series capacitor it is grouped in this report with Power Electronics due to the thyristors that provide finer control of the reactive compensation.

Power Electronics:

The facilities that fall under this category are actually a collection of various high voltage electrical equipment and their control and protection systems. Most of these facilities were purchased and installed as complete facilities that include not only the power electronic components such as thyristors and varistors but various switchgear, reactors, capacitors, and control circuits that make up the complete converter or reactive compensation package. These facilities include the DC Converter (Celilo) used for AC to DC conversion to facilitate power transfer over long distances with fewer losses.

The Static VAR compensators at Keeler and Maple Valley provide very precise voltage control and support particularly for sensitive load areas. Similar to the Series Capacitors listed above the TCSC at Slatt provides additional transmission capacity by compensating for the inductance on long lines. The TCSC is included with this equipment group because of the thyristors and similarities in maintenance to. Surge arresters (Metal Oxide Varistors – MOV's) provide high energy, short-duration impulse and over-voltage protection to station equipment such as transformers, circuit breakers, reactors, capacitors, and transmission lines.

Low Voltage Station Auxiliary – LVSA:

Included under the **LVSA** substation assets are certain lower voltage (LV >600VAC < 12.5kVAC; 48VDC – 125VDC) supporting electrical equipment and components. These include the AC station service panels and transfer switches, substation grounding, grounding cells/cathodic protection, engine generators, DC station control batteries, and underground SS cable.

Substation asset age and health is discussed in the next section and as will be seen, age is only one factor that determines the useful life of this asset group. In regard to HV electrical equipment factors such as the frequency of operation, type and severity of duty, and level of maintenance generally have greater impact than age alone it is still interesting to note the overall age demographics in the chart below. For amortization purposes BPA Substation Assets are expected to last from 20 to 40 years depending on the equipment type. The following chart shows the aggregate age demographic for roughly 25,000 pieces of electrical substation equipment for which age data was available. Data for the NEP age and health demographics is still under development.
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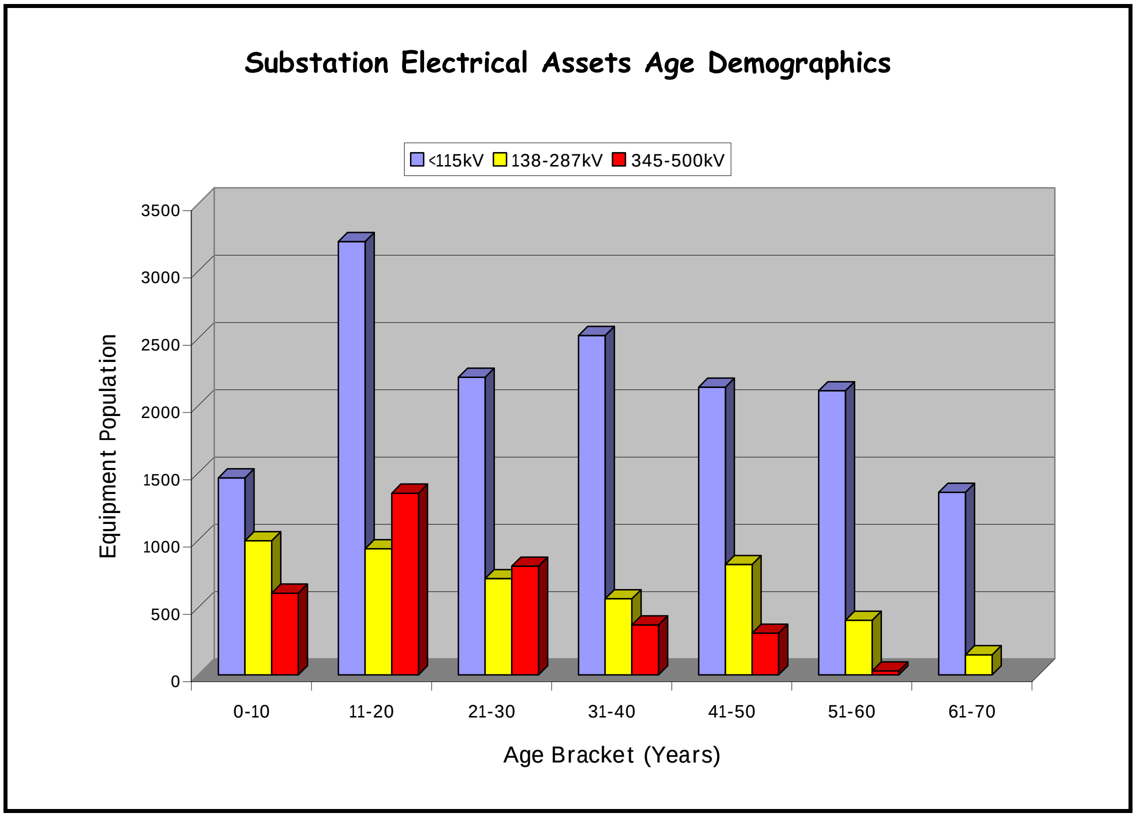


Figure 2.1 Substation Electrical Assets Age Demographics

A surprising portion of BPA's electrical substation assets well exceed both BPA's capitalization criteria as well as typical industry metrics for electrical equipment lifespan. The average age of the equipment in the above chart is 31 years and the percentage of equipment in excess of 40 years is 34% with the average age of equipment over 40 years being 52 years. It is anticipated that improvements in tracking and trending methods combined with increased monitoring of equipment operation and operating duties will improve our ability to predict the probability of failure.

3.2.2.3 Substation Asset: Health Demographics and Assessment

Substation Asset health, not unlike Overhead Assets (transmission lines), is difficult to asses in the aggregate due not only to geographic and environmental variations equally important is the varying electrical system conditions. Substation electrical equipment such as the switchgear employed in terminal equipment is designed for and exposed to the most severe electrical operating conditions that exist. Since system operating conditions vary greatly, as does the specific application and actual usage, the degradation of substation equipment can vary considerably with duty.

Manufacturer designs can also vary considerably and the national and international technical standards that guide the design and testing of high voltage electrical equipment only provide minimum levels of standards intended to meet the needs of the typical utility. The BPA transmission system has many atypical attributes that frequently challenge conventional high voltage equipment designs. Large concentrations of power generation have pushed fault currents to the upper limits for many power circuit breaker manufacturers and very long transmission lines create both steady state and transient overvoltage conditions not adequately accounted for by many manufacturer designs.

The LVSA and NEP asset categories are much more impacted by age and particularly environmental factors. Similar to Overhead Assets substation structures, ground mats, buildings and foundations are subject also to weather components (moisture, frost, UV), mechanical loading (wind, ice, thermal expansion/contraction)

Substation Overall Health Demographics

Substation Asset	Physical Condition			Obsolesence			Remaining Life			Asset
Major SubCategories	Good	Fair	Poor	Good	Fair	Poor	10-20	5-10	<5	Health
Transformers (Power)										Good
Transformers (Instr.)										Good
Transformers (SS)										Good
Shunt Reactors										Good
Series Reactors										Good
Switchgear:										Good
Breakers										Good
Circuit Switchers										Fair
Disconnects										Good
GIS										Good
Fuses										Good
Shunt Capacitors										Good
Series Capacitors										Good
SVC's & TCSC										Good
DC - Celilo										Fair
LVSA										Fair

Table 2.2 Substation Overall Health Demographics

BPA's overall approach and strategy to managing Substation Assets is to maintain, repair, and rebuild high voltage facilities for their expected lifespan or until condition factors, obsolescence or maintenance costs dictate replacement. Due to BPA maintenance practices the lifespan of most high voltage electrical substation equipment has historically exceeded their respective lifespan. These categories are all developed in greater detail in the Appendix of this report and can also be found in the Asset Health Assessment of June 2007 and will be reflected in the updated Submaintenance 2008 report.

3.2.2.4 Substation Asset: Risk Assessments

The vast majority of electrical substation assets are in good condition. However, condition assessment for LVSA and NEP are currently not as well tracked in the aggregate but data for problem areas are documented. Figure 2.4 plots the overall impact or risk of Component Health against System Impact. There are a few subgroups among these major categories with equipment in fair or poor health that cannot be individually identified in the figure below. Since the primary intent of this report is to manage assets to limit risk both financially and operationally the focus will be primarily on those assets listed in Fair or Poor condition. For reference the Appendix contains additional detailed information on the specific maintenance and replacement programs and additional asset demographics that better define the entire asset population.

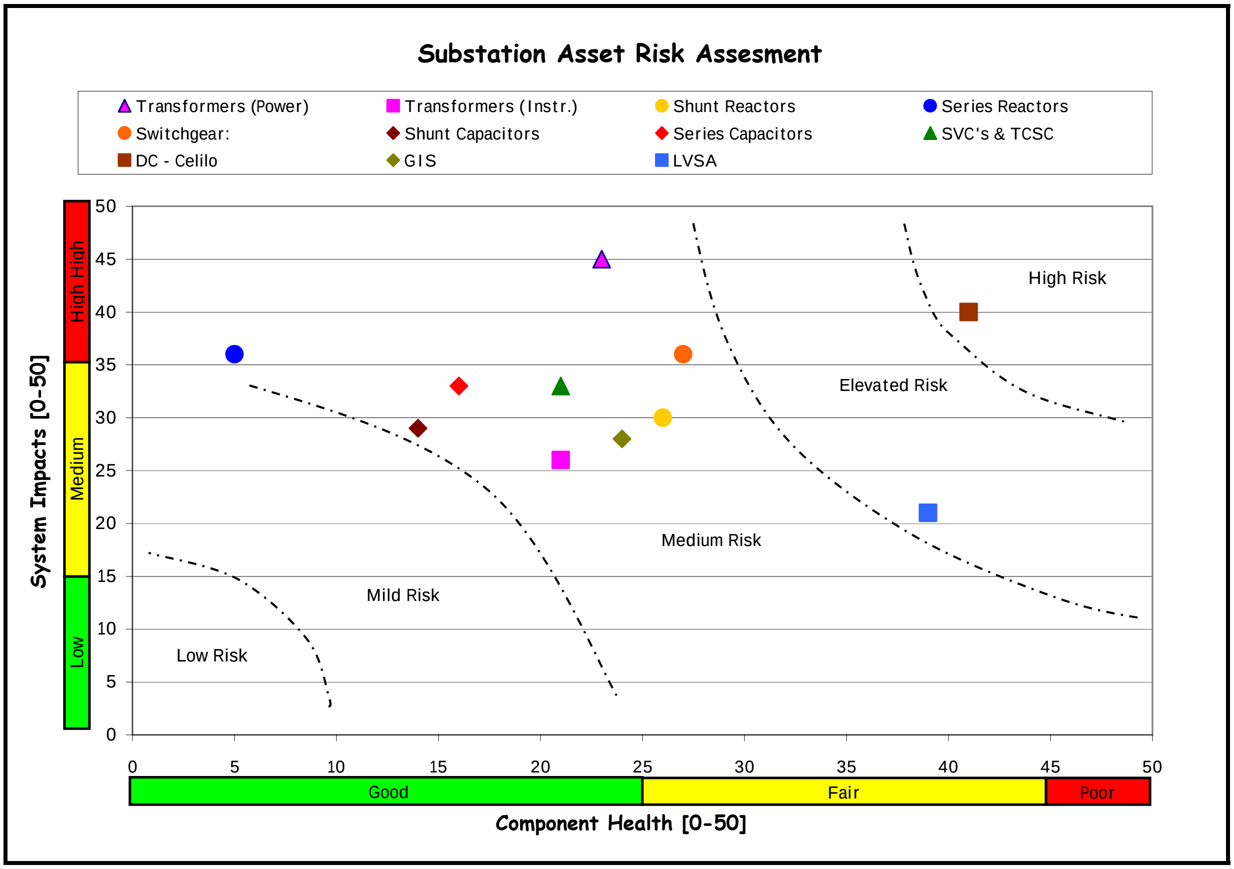


Figure 2.3 Substation Asset Risk Assessments

Included in the risk assessment for 500kV transformers is consideration of the substation and transmission line rankings developed under the "Priority Pathways" effort. Additional risk factors will be implemented in future revisions of this plan that reflect new and developing criteria, such as those identified to meet regulatory requirements for operation and maintenance (backlogs) of Substation assets. Within the major substation asset categories there are several asset subgroups that are the current focus of this report due to their fair or poor condition assessment, potential system impacts, and regulatory requirements.

As an overall asset specific category, such as transformers, a chart showing overall system condition and/or risk will tend to mask the health and risk components for the total population. Specific conditions may vary dramatically within the asset category population. For this reason please see risk figures 2.3.1 and 2.3.2.

Following are the Key Drivers against which condition and system impacts are evaluated for replacement prioritization.

- Equipment end of life issues;
- Equipment maintainability and availability;
- Equipment security and exposure to hazards;
- Obsolescence and original equipment manufacturer support; and
- Legislative and regulatory compliance.

Wirewound Equipment - Risk Assessment

Under the Wirewound equipment power transformers and power reactors pose the greatest operational risk to the system and in some cases pose environmental risks where chronic oil leaks are an issue. A particular risk factor concerning service restoration is the current global demand for transformers which has put lead times for large 500kV transformers and reactors at about 24 – 36 months. Events in the past two years have demonstrated that BPA has limited ability to obtain large (1300+MW) 500kV transformers or reactors from other utilities even on a temporary, loan, basis. The 2006 and 2007 calendar years alone have seen 6 transformers and two reactors fail, all but one of these were 500kV.

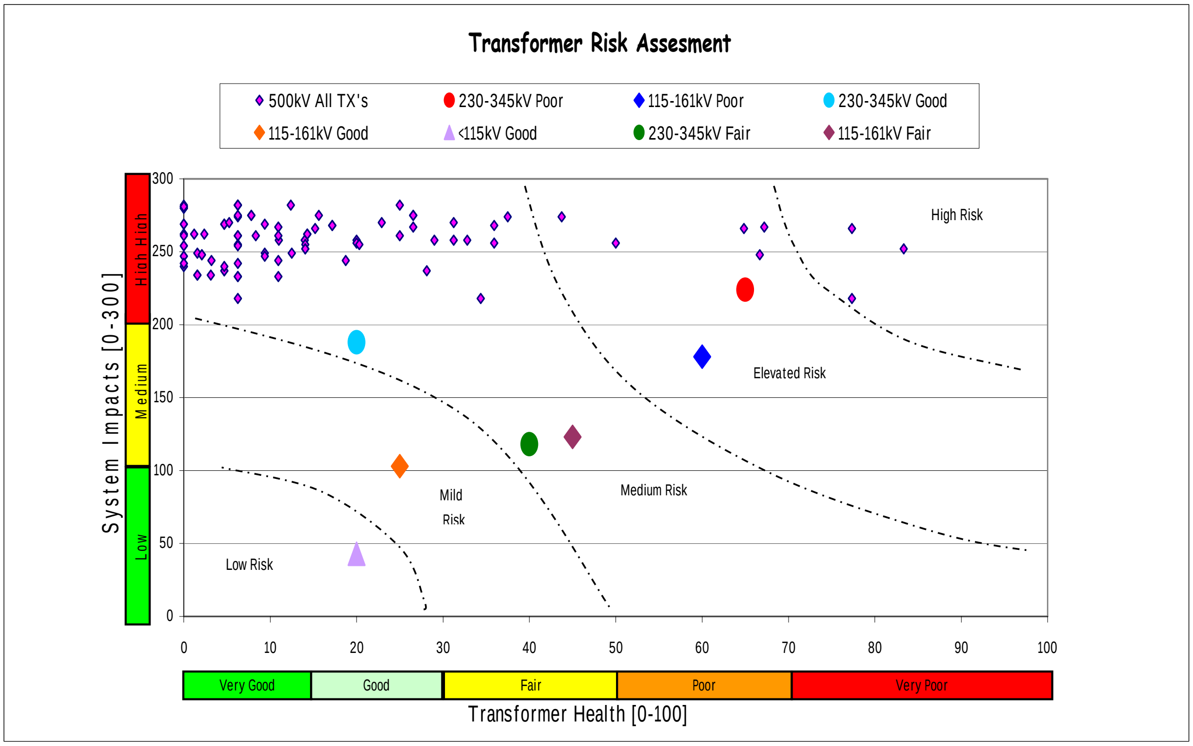


Figure 2.3.1 Transformer Risk Assessment

Transformer EMS Spares

The current fleet of spare transformers may not be adequate to respond to multiple contingencies or large scale events (seismic or terrorist) depending on the location. Figure 2.4.1 plots transformer Health against System Impact. The 500kV transformer health assessment was based on an aggressive five tier evaluation criteria and matched with the corresponding Priority Pathway (PP) ranking for each location. The 500kV transformers all ranked within the top 30% in the PP ranking and are all listed as Significant Equipment per Operating Bulletin (OB) 19. Current statistical estimates (mean time between failure –MTBF) indicate that BPA can expect a transformer failure of one per year based on a 500kV Transformer Spare Policy Review by TESM.

Instrument Transformers

BPA still has a population of Oil filled current transformers for which the failure mode of oil paper insulated porcelain enclosed transformers can be catastrophic depending on the manufacturer. There are approximately 100 oil insulated 500 kV current transformers remaining on the system. The insulation system on oil filled units experience high stresses during normal operation. Replacements of the oil CT's is generally coordinated with replacement of the associated 500kV breaker. In addition, there are approximately 105, 500kV Capacitive Voltage Transformers (CVT's), that are 35 years and older. Drifting of the Capacitive materials causes inaccuracies that affect the reliable operation of relays and revenue metering accuracy.

Transformer Tertiary ground protection upgrade:

Ground faults on the tertiary can result in over voltages (neutral shift) that can fail either the tertiary bushings or windings depending on individual transformer insulation levels. One hundred and two autotransformers with delta-configured tertiary windings require this upgrade. There remain approximately 15 installations to be completed.

Switchgear – Risk Assessment

The dominant risk factors associated with switchgear are end of life (due to steady state, fault duty, thermal failure, or safety), obsolescence, design flaws, and maintenance issues driven both by condition and NEPA (Gas & Oil).

Certain breakers ranked "fair" reflects the fact that the breaker has a known safety issue (minimum-oil breakers) or would have to be replaced under an emergency WO scenario in the event of a mechanical failure of the operating mechanism or the interrupter due to a design-flaw issue or spare-parts issue.

Certain populations of 230kV Circuit Switcher equipment are severely affected by loss of OEM. In some cases their unique compact design creates additional space constraint issues because there are no replacements on the world market with a similar compact design. This poses a particular risk where emergency replacement with a breaker or other type of circuit switcher device would incur considerable delays to expand substation yards or relocate other equipment. The strategy is to replace these switchers under a planned scenario and before a forced event in order to address the space limitation.

Since 2001, approximately 211 disconnects have been replaced based on fault duty ratings. BPA expects to replace about 15 disconnects per year due to increasing fault duty, load growth, and a load break disconnect upgrade program on transmission field switches. This program level represents 0.3% of the total disconnects per year on the system.

The EG-1 type fuses are listed “poor” because the manufacturer (G.E.) does not make them anymore and spare parts are no longer available. Replacement of the EG-1’s, as well as the liquid filled fuses listed below, need to be planned or scheduled due to disruption in service to customers and environmental (PCB cleanup) issues. When an EG-1 type fuse blows the equipment cannot be put back into service until the whole assembly which includes the base, insulators, hardware and fuse are replaced. . Since many of these fuses are located at customer service station and there may be no alternate source the additional outage duration can significantly impact SAIDI. The liquid filled fuses are rated poor because of the well-known environmental concerns with internal PCB contaminants that are released when a fuse blows.

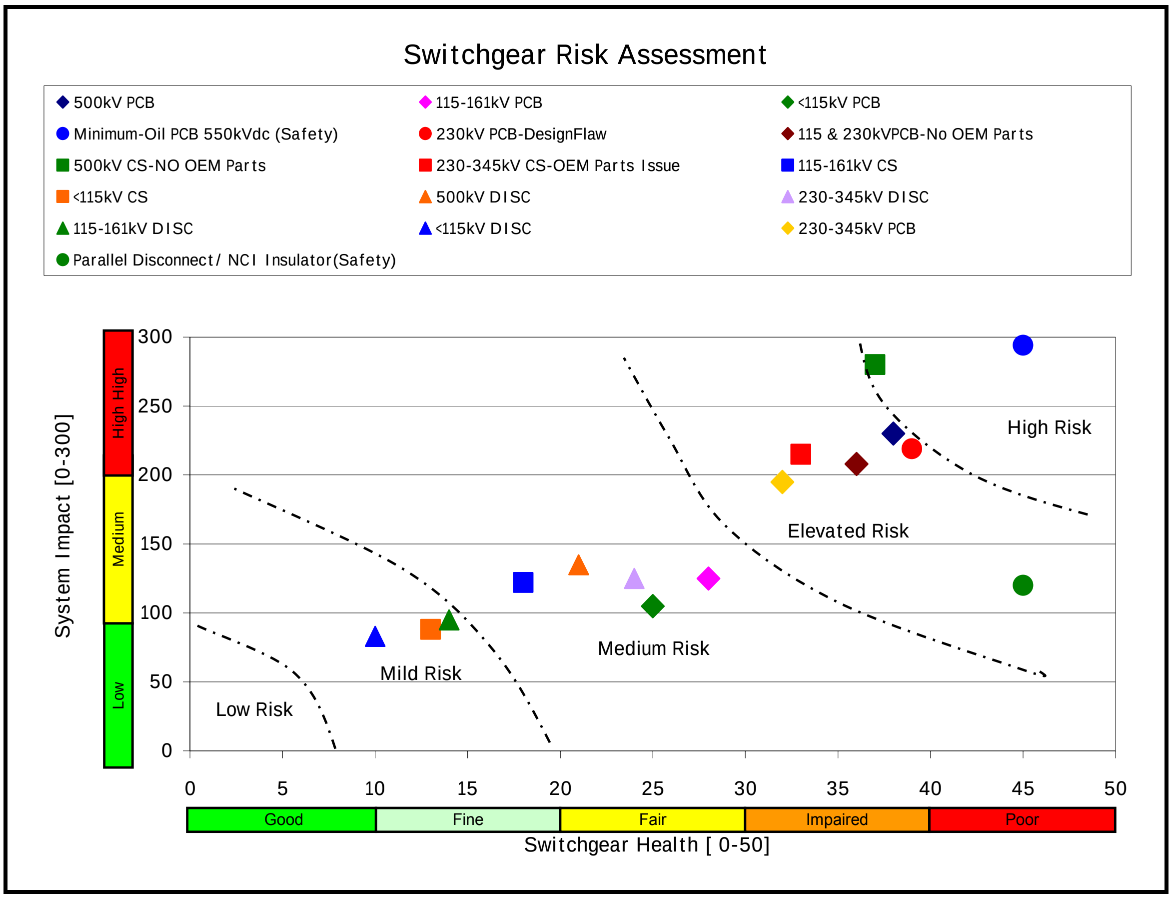


Figure 2.3.2A Switchgear Risk Assessment

BPA Gas Insulated (GIS) Equipment Health Index											
Major Facility	AC PCB's	AC CS's	AC Volt. Transf.	Battery	Reactors	AC Current Transf.	Power Transf.	Station Service Transf.	AC MOV's	AC Disc's.	Overall Asset Health
Buckley	Fair	n/a.	Good	Fair	n/a	Good	n/a	Good	Good	Good	Good
Ponderosa	Good	n/a	Good	Fair	n/a	Good	Good	Good	Good	Good	Good
Taft	Good	Good	Good	Good	Good	n/a	n/a	Good	Good	Good	Good

Table 2.3.2B GIS Equipment health Index

Capacitors – Risk Assessment

BPA's capacitor facilities are currently in good condition but a small number of shunt capacitor installations are exhibiting elevated rates of capacitor can failures, compared to the system average. due to aging of the insulating materials. Capacitors at Shelton (55yrs),Toledo (51 Yrs), Tacoma (40yrs) and a few others in the 30-40 year age bracket will need to be replaced.

For Series capacitors the most significant risk factors, pertaining to reliability and obsolescence, are the electronic control and protection systems for the eight 3rd AC Intertie installations. These controls systems will need to be closely monitored and diligently maintained in the next few years to maximize their lifespan.

Power Electronics – Risk Assessment

HVDC Converter Celilo:
The original BBC transformers on Converter 1 and 2 have a flawed sealed bushing design that has failed catastrophically on four transformers. While bushing replacement may be possible, it is technically complex and 40-60% of the cost of a new transformer. There have been two failures of DC smoothing reactors without any replacements. We have one "universal" spare left for the four converters. The universal spare was designed for Converters 3 and 4 and is not drop-in compatible with Converter 1 and 2 buswork and controls. The remaining Converter 1 and 2 DC smoothing reactors have sealed bushings with the same problems as the BBC transformer banks.

Main controls for Celilo have been added in several vintages. The newest control vintage is beyond its design life. The Craftsmen at Celilo have been repairing boards by acquiring obsolete parts on the "grey market." It is increasingly difficult to find electronic components to repair the controls. We have recently been having problems with power supplies that have affected availability. In general, SPC at Celilo has been making a lot of heroic efforts to keep the controls functioning. Despite this, there have been many failures that have affected availability, and we have been having power quality issues related to the controls. Significantly, the firing controls for Converter 3 and 4 are the original bias cosine design created for the old mercury arc valves, which do not perform as well as we would like for power quality.

Some switching equipment for the AC and DC yards are reaching or are beyond end of life. These include bypass breakers for Groups 1-8 (7 and 8 are scheduled for replacement), DC disconnects, and some AC switchgear. The S&C switchers in the AC yard have seen some significant failures recently and there are no spares in BPA and few replacement parts anywhere.

We have been having a much higher than expected failure rate for the new Siemens light triggered thyristors. Recent analysis showed problems with voltage punch-through, possibly related to the recovery protection.

On Converter 1 and 2 DC filters, the original Westinghouse capacitors tend to fail and cause outages. There is a submitted proposal to replace the capacitors in these banks but no final decision at this time. We anticipate needing to replace the Converter 3 and 4 filter capacitors within 20 years, possibly 10.

We have power system reliability and quality issues related to station service that need to be fixed. For example, with the MG sets significantly unloaded after the Mercury Arc Valve Replacement Project, the second harmonic oscillations have become much more problematic.

Celilo HVDC Converter Station Overall Health Assessment												
Direct Current (DC) Equipment												
Major Component	Valves	Valve Base Electronic	Valve Cooling	DC Controls	DC Protection	DC Filters	Comm Links	DC Arresters	DC Disconnects & Bypasses	DC Measurment Systems	DC Lines	Overall Asset Health
HMI							Fair					Poor
Bipole				Poor	Fair		Fair				Fair	Fair
Converter 1	Good	Good	Good	Fair	Fair	Poor	Fair	Good	Fair	Good		Fair
Converter 2	Good	Good	Good	Fair	Fair	Poor	Fair	Good	Fair	Good		Poor
Converter 3	Good	Good	Good	Poor	Poor	Fair	Fair	Good	Poor	Poor		Fair
Converter 4	Good	Good	Good	Poor	Poor	Fair	Fair	Good	Poor	Poor		Fair
RAS										Poor		Fair

Alternating Current (AC) Equipment											
Major Component	AC Protection	Converter Transformers	Station Service	Battery Systems	AC Harmonic Filters	AC Circuit Switcher	AC Breakers	Building HVAC	AC Arrestors	AC Disconnects	Overall Asset Health
Converter 1	Poor	Poor	Good	Good	Good		Good	Good	Good	Good	Fair
Converter 2	Poor	Poor	Good	Good	Good		Good	Good	Good	Good	Fair
Converter 3	Good	Fair	Good	Good	Good	Poor	Good	Good	Good	Good	Fair
Converter 4	Good	Fair	Good	Good	Good	Poor	Good	Good	Good	Good	Fair

Figure 2.3.5 Celilo HVDC Converter Station Overall Health Assessment

Since the HVDC converter is a unique facility and to some extent the energy transmitted has a strong commercial component serving load outside of the NW region, its system impact is not included in the Substation Asset Risk chart at this time and is currently under evaluation.

Static Var Compensators (SVC's):
The two SVC facilities at Keeler (230kV) and Maple Valley (500kV) are approximately 25 years old and the most impending risk is the obsolescence of the GE control and protection circuits. These facilities are experiencing similar problems as the DC converter but to a lesser degree in terms of patch and repair of the controls. A ten year asset plan will need to include provisions for the replacement of the control systems at these stations and these figures are not yet available.

Arresters – Metal Oxide Varistors (MOV's):
The transmission system has about 4250 surge arresters installed from 15 kV up to 500 kV. At present approximately 1100 of these arresters are of the old, SiC gap-type, and are in poor condition because they no longer perform the protective function for which they were designed. The primary problems are due to sealing failures and gap erosion. Arresters failures result in line to ground faults that will stress transformers and reactors with

close-in (bus fault) high magnitudes through faults. BPA has a replacement program of these SiC arresters with new, metal-oxide type arresters.

Low Voltage Station Auxiliary (LVSA) Equipment - Risk Assessment

Most LVSA are replaced on an emergency basis due in part to limited ability to predict failures Other than age and in some cases leaks (SS TX) most of this equipment does not have reasonably measurable condition factors and the resources needed for such tracking are not commensurate with actual failure rates, risk, or replacement cost.

However, certain assets under LVSA are best replaced under planned replacement programs since they can have significant system impacts (long duration to replace) including operational disturbances and safety. The primary examples include replacement of ground mats, substation cables, and substation DC control batteries.

As an example, combining a three year outlook on station batteries currently on the BPA System, the following is a forecast of batteries that will have exceeded their life expectancy by 2008. The current rate of replacement, as emergency replacements, is approximately 15 per year.

- 98 out of 210 Vented Lead Acid batteries on the System (47%)
- 9 out of 16 VRLA (56%)
- 6 out of 34 NiCad (18%)

3.2.2.5 Substation Asset: Investment Recommendations

Wire-wound Equipment Replacement Program

Description:

Typically BPA experiences three (3) failures per year of major power transformers and/or reactors. In 2006 -07 failures = 6 Transformers & 2 Reactors. Current lead times are app. 24 months. Included in these replacements are various instrument transformers, station service transformers, and tertiary ground protection schemes for transformers.

Key Drivers:

- Equipment End-of-life
- Equipment Operability, Maintenance -Full life-cycle costs
- Obsolescence and Original Equipment Manufacturer (OEM) Support

- Legislative, Regulatory or Contractual Obligations (NEPA – Oil & Noise)

Issues Being Addressed:

Replace a number of aging and unreliable, or failed transformers.

Program Management:

This is a recurring program for all Wirewound equipment except the Tertiary Ground Protection Schemes that may be completed in two years depending on funding and resource levels.

Switchgear Replacement Program

Description:

Replace all switchgear that no longer meets continuous or momentary current carrying requirements – Regulatory Safety requirement. Replace a number of aging and unreliable circuit breakers, circuit switchers and disconnects at various substations**.**

Key Drivers:

- End of Life, Design, Safety; Reliability, Maintenance Costs-Full life-cycle costs
- Availability of OEM support (parts, technical support);
- Change in operating conditions;
- Environmental issues such as Oil & SF6 gas leakage;
  Seismic withstand requirements

Issues Being Addressed:

The reasons for replacement range from underrated for current, poor reliability, inability to obtain spare parts, lack of OEM support, high cost of maintenance, and general end-of-life issues.

Program Management:

This is a recurring program.

Capacitors (Shunt & Series)

Description:

Replace aging shunt capacitor groups due to insulation degradation and depletion of spare cans. Replace control and protection circuits for the 3rd AC Series capacitors due to failing components, diminishing spare parts and vendor technical support, and increased maintenance costs.

Key Drivers:

- Equipment End-of-life
- Equipment Operability, Maintenance -Full life-cycle costs
- Obsolescence and Original Equipment Manufacturer (OEM) Support
- Change in operating conditions;

Issues Being Addressed:

The reason for shunt capacitor replacements is primarily degradation of capacitor insulation. As replacement cans for the older cap groups are depleted the entire group will eventually need to be replaced. In addition, capacitor group replacements will frequently be a different size than the original due to changes in operating conditions.

Program Management:

Shunt capacitor replacements are a recurring program, however since so many shunt capacitors are fairly new it is anticipated that the program will have periods of little to no activities. The Series capacitor control replacement is a one time project that will take 3-4 years.

Power Electronics Replacement Program

Celilo

Key Drivers:

- Equipment Operability/Reliability
- End of Life - Design, Reliability
- Availability of OEM support (parts, technical support);

SVC's & TCSC

Description:

Power electronics require extensive and complex control and protection systems not only to operate the primary reactive components but also to manage and control the harmonics associated with most power electronics. The expected lifespan of many of these components is on the order of 20 years. Current strategies include patching and repairing and as spare parts are depleted complete replacement will be required to achieve reliable operation. The DC Converter station also has significant issues with high voltage equipment aging and loss of OEM parts and support.

Key Drivers:

- Equipment Operability/Reliability
- End of Life - Design, Reliability
- Availability of OEM support (parts, technical support);

Issues Being Addressed:

Declining performance of the Siemens thyristors, age related and operational problems with DC filters, and both DC and AC switchgear.

Program Management:

The controls replacement for all projects is roughly 3-4 years beginning with scope development, specifications, RFP/RFQ, Design, and at least two years for installation and testing. The DC converter replacements and upgrades will take an additional year or two particularly to manage outages and availability while the various systems are replaced.

Surge Arrestor Replacement Program

Description:

Replace a number of high voltage surge arresters at various substations. Replacement of aging and failing gap-type arrestor will provide greater protection for existing assets from lightning and switching surges that can damage equipment.

Key Drivers:

- Equipment end-of-life
- System reliability
- Safety

Issues Being Addressed:

The surge arrestor program replaces aging and failing gap type arrestors. The oldest SiC arresters (very few remaining) are prone to destructive failures when venting.

Program Management:

With roughly 1100 SiC gapped arresters this is a long term program (11 years+) that may be completed by 2019 assuming a planned replacement of 100 per year.

Low Voltage Station Auxiliary Equipment Replacement

Description:

Replace miscellaneous auxiliary equipment at various substations. Station auxiliary equipment includes any equipment used to support the power delivery system excluding the items in the previous four sections. The table above currently only reflects DC station control batteries and station cables, data for other items is pending.

Key Drivers:

- Equipment end-of-life
- Safety
- Equipment operability

Issues Being Addressed:

Replacements of station DC control batteries, cables, and grounding systems should be planned vs. emergency. When these facilities are not available due to degradation or failures system reliability, crucial station support functions, and safety are adversely impacted.

Program Management:

This is a recurring program.

3.2.3 System Protection and Control

This System Protection and Control asset plan is based on a comprehensive review and assessment that was completed in 2007 of the system protection and control equipment assets, including age and health demographics and risk assessment to BPA's business and mission critical success. In addition, the plan will recommend an appropriate investment level to mitigate known or suspected risks to BPA's long term strategic objectives. Aging, for this effort, is defined as the deterioration over time of critical equipment or a component's mechanical, electrical, or thermal performance capabilities significantly increasing their risk of failure. Aging also includes critical component obsolescence where it results in the inability to timely respond to component failures threatening system integrity and/or electrical service continuity.

3.2.3.1 System Protection and Control Asset: Overview

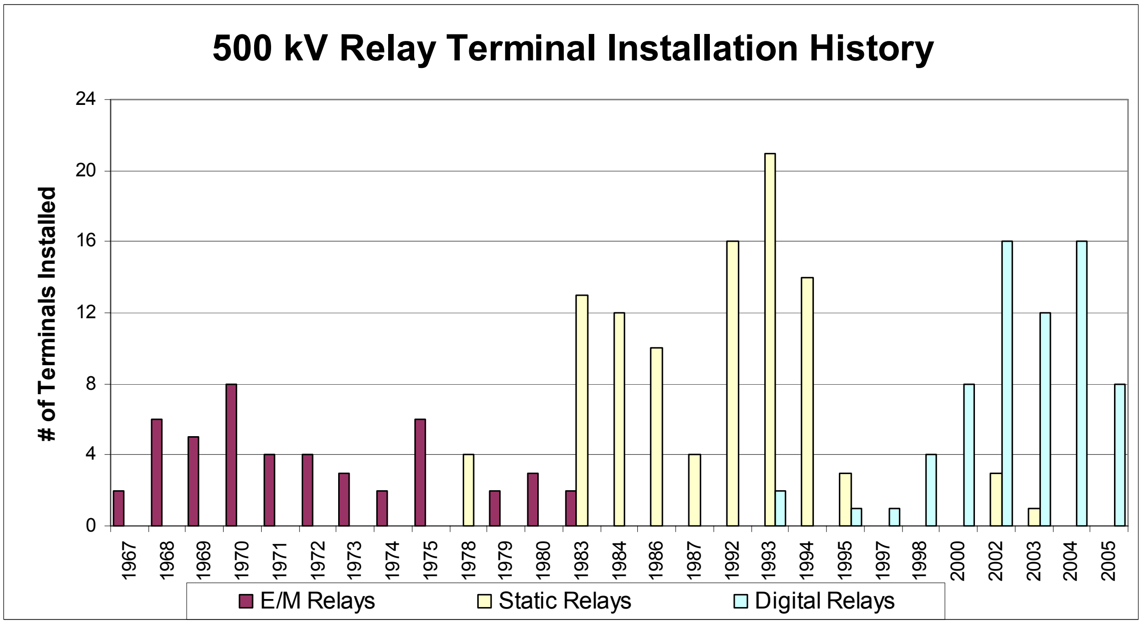
Protection and control assets consist of protective relaying, monitoring, metering and control systems at transmission substations. These assets protect transmission equipment from damage due to electrical and mechanical faults, ensure stability and reliability of the transmission system, protect the public and personnel and provide local and remote control and monitoring of transmission equipment. These assets also provide accurate metering and control of the electrical grid.

These assets incorporate a variety of electro-mechanical, electronic, and digital equipment that measure voltage, current and other data at key points in the substation and convey that information to protection and control equipment within a control house or control center. This information is transmitted to the system control centers via SCADA, telemetering and sequential event recorders (SERs) via telecommunication facilities. Alarms alert substation operators and dispatchers to abnormal conditions that require investigative or corrective action. In general most stations are unmanned and operated remotely from the control centers.

The protection and control systems are a supporting component of the primary circuit elements of the transmission system but are a critical component with respect to preserving the life of the primary circuit elements, maintaining the overall reliability of the system, and insuring public safety.

3.2.3.2 System Protection & Control: Age Demographics and Assessment

Currently, SPC's protection and control equipment is not numbered and is not been tracked in an official database. Therefore, specific ages of protective relays, meters, fault recorders, etc., is nearly impossible to obtain. Some staff members have maintained their own inventories of specific equipment types and the installation dates. As an example, the following graph shows the installed date and protective relay type for 500 kV line terminals. Unfortunately, similar installation data is not available for other protection and control assets.



There are 47 500 kV line terminals still equipped with electro-mechanical relays, the oldest nearly 40 years old, the newest 24 years old. Beginning in 1978, BPA began using electronic or static relays on 500 kV line terminals, almost exclusively from European vendors. Many existing terminals of electro-mechanical relays were replaced with static relays and single pole switching in the early 1980s. 101 terminals are equipped with static relays, the majority installed between 1983 and 1994. The current protection practice is the use of digital or microprocessor based relays which also have single pole switching capability.

Electro-mechanical and digital relays are used for protection of the lower voltage transmission lines. Very few line terminals are equipped with static relays. BPA began installing digital relays in the late 1980's for new line terminals or relay replacements. At least 45% of the lower voltage line terminals are still equipped with electro-mechanical relays, many dating from the mid 1960's.

3.2.3.3 System Control & Protection Assets: Health Demographics and Assessment

The SPC asset is a large and complex physical and electrical system when examined as an aggregate so is difficult to characterize as on overall entity. In order to build a quantitative evaluation of the assets overall health, the SPC assets were separated into major components organized by common health related attributes.

We anticipate that major components of SPC assets will age at different rates necessitating risk management and assessment strategies tailored to the characteristics of each major SPC component. Major SPC components are grouped and identified as populations which facilitate efficient health assessment and risk management organization dependent on 1) their criticality to system performance, 2) aging related characteristics, 3) concerns for obsolescence, and 4) sub-component connectivity.

Seven major SPC components have been identified. The table below lists those components and their overall health.

Overall Component Health Demographics							
Major	Maintainability			Obsolescence			Asset
Component	Good	Fair	Poor	Good	Fair	Poor	Health
Electro-Mechanical Relays							
500 kV							Impaired
230-345 kV							Impaired
69-169 kV							Impaired
< 69 kV							Impaired
Transformer & Reactive							Impaired
Special Protection & Control Schemes (RAS)							Impaired
Electronic Relays							
500 kV							Poor
230-345 kV							Poor
69-169 kV							Poor
< 69 kV							Poor
Transformer & Reactive							Poor
Special Protection & Control Schemes (RAS)							Poor
Digital Relays							
500 kV							Fine
230-345 kV							Fine
69-169 kV							Fine
< 69 kV							Fine
Transformer & Reactive							Fine
Special Protection & Control Schemes (RAS)							Fine
SERs							Impaired
DFRs							
Rochester							Impaired
Bens							Good
Revenue Meters							
Electronic							Fine
Digital							Good
Remote Metering Systems							Impaired

The oldest electro-mechanical relays are in poor condition. Insulation on wires has become brittle and many of the individual parts are no longer available. Electronic relays, especially those installed on the 500kV grid have a high rate of power supply failures. BPA has traditionally assumed at least a 30 year life expectancy for electro-mechanical relays. Electronic and digital relays have a much shorter operating life, approximately 15 to 20 years.

Digital devices may be closer to the 15 year life expectancy because of rapidly changing integrated circuit technology which results in equipment obsolescence before it reaches its end of life. Already, we are seeing that the central processing units CPUs for early digital relays are no longer available so a CPU failure will cause a complete replacement of the device. Similar unavailability problems with other digital components such as mass memory storage exist. We expect similar operating life spans and problems for most other SPC electronic and digital equipment such as fault recorders, event recorders, and metering.

Digital devices require a high rate of firm ware or operating system updates throughout the life of the device. These updates are required to correct errors and faults detected in the device's operating system. For protective relays, if uncorrected, these problems can result in a failure to trip or a false trip of a critical circuit element.

The North American Reliability Council (NERC) has recently implemented numerous reliability standards that affect BPA's protection and control practices. To comply with these standards we must replace many of our older protection and control schemes.

3.2.3.4 System Protection and Control Asset: Risk Assessment to Operating System

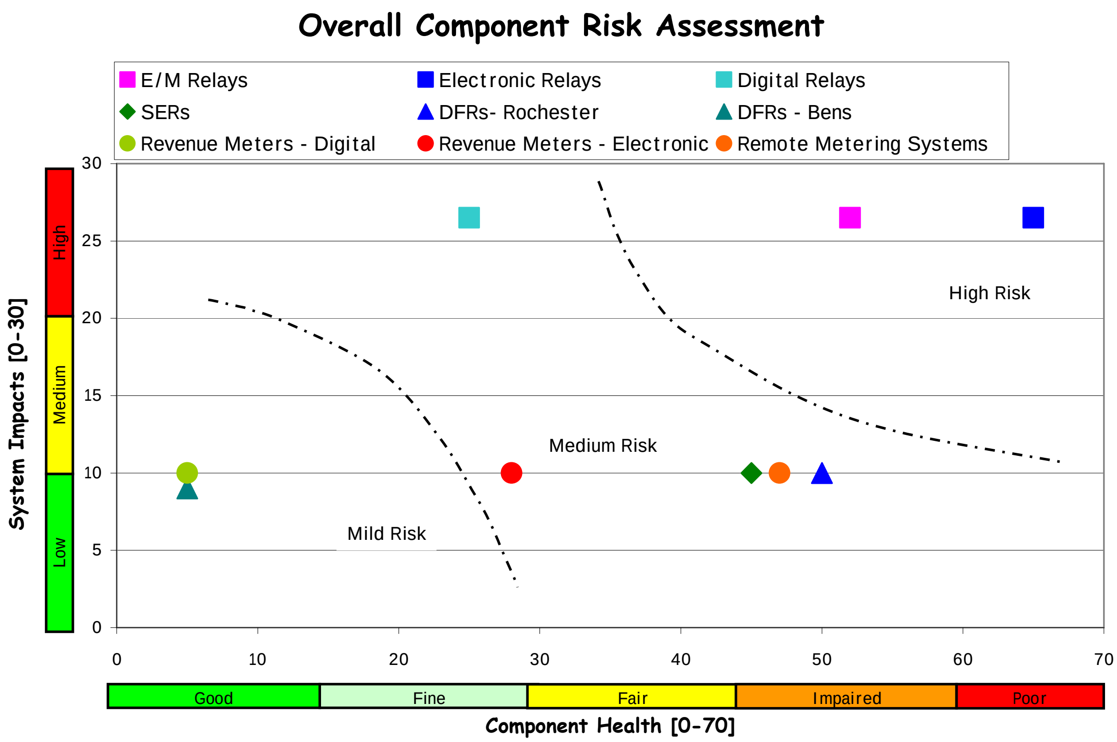
Staffing

The SPC work force is facing a large loss of skilled craftsman and engineers due to retirements. New engineers and craftsmen are being hired but face years of on the job training before they can fully support the SPC function. The older obsolete electrical/mechanical and electronic devices require a much longer training sequence to achieve proficiency. With fewer fully trained employees to provide guidance and direction on the older devices, training on the obsolete devices is becoming critical. As more digital equipment is being installed side by side to the older obsolete electrical/mechanical and electronic equipment, the learning curve is increasing considerably to maintain all types of devices. The lack of adequately trained SPC craftsmen puts BPA at risk of non-compliance with NERC mandatory protection standards.

A systematic planned replacement program for the older, obsolete electrical/mechanical and electronic devices would relieve most of the staffing pressure centered around training, and loss of institutional knowledge to maintain them.

3.2.3.5 System Protection & Control Asset: Risk Assessment and Overview

Equipment risk assessment is summarized in the risk map below. System Impacts are plotted against Component Health providing a measure of a component's overall risk in terms of physical health, obsolescence against operation impacts to system reliability and asset availability. The plot is organized into essentially three regions from High Risk in the upper right corner to Mild Risk in the lower left corner.



3.2.3.6 System Protection & Control: Recommendations and Future State

Based on the overall health and risk assessment this asset plan has a number of recommendations needed to meet Agency and Transmission Services strategic long term outcomes. The fundamental goals and drivers for these recommendations are focused on 1) improving the overall health of the installed SPC assets to a Good status to ensure its continued success and 2) provide proactive processes to manage and assess the SPC asset as it continues to age to demographic levels which BPA has little or no experience managing and mitigating. As these goals and drivers are common across the industry both locally and globally, a more proactive strategy and approach requires development in order to have adequate assurance of success. Inadequate or improper management, assessment, or mitigation processes inconsistent with the new challenges of a significantly aged SPC asset can easily result in gross loss of reliability and/or availability threatening the very mission and business success of BPA and its stewardship of the Region it serves.

This SPC asset plan recommendations essentially fall into four groupings addressing the goals and drivers discussed above. The groupings are;

- Aggressively pursue an active replacement program for five programs identified as being in poor health or obsolete
    1. E/M & Electronic Relay Replacements
    2. Digital Relay Replacements
    3. DFR Replacements
    4. SER Replacements
    5. Metering Replacements

- Continue to characterize and assess the SPC asset at an adequately granular level both temporarily and spatially to facilitate proper proactive management.
- Continue to develop the Transmission Services' Asset Information System (TAS)
- Continue to develop and improve documented strategies to better manage and mitigate the adverse effects of aging, or age related degradation processes, in a manner which ensures the continued success of the reliability and availability of the overhead asset.

While we have collected known demographic data on these assets, there are many inconsistencies and inadequacies with present processes and demographic data, in meeting our goal of being PAS-55 compliant by 2010. Using a reactive strategy with minimal quality data, which has served BPA in the past, will be grossly inadequate as the assets age into the future.

3.2.3.7 Investment Recommendations

E/M & Electronic Relay Replacement Program

Description: Replace E/M and electronic relays with microprocessor based digital relays.

Key Drivers:
- Equipment end of life

- Equipment obsolescence
- Maintenance costs
- NERC, WECC and FERC Standards

Issues Being Addressed: The existing relays have been in service for 20 plus years. Spare parts and replacements are difficult to impossible to obtain. Digital relays provide information that older relays cannot such as fault location and fault magnitude which is used to locate reoccurring line trouble or in coordination with other relays. Knowing the location of a permanent fault will decrease the outage time, enhance customer service, the improve BPA's SAIDI measure. Digital relays can be accessed remotely so operators do not have to travel to the substation. Additionally digital relays have extended preventive maintenance intervals and require less maintenance time per unit. This is particularly important given the trend that our workforce of SPC engineers and technicians is decreasing.

Digital Relay Replacement Program

Description: Replace digital relays installed in the early 1980's. These relays are obsolete, no longer supported by the vendor and do not meet NERC and WECC mandatory standards.

Key Drivers:

- Equipment end of life
- Equipment obsolescence
- Maintenance costs
- NERC, WECC and FERC Standards

Issues Being Addressed: The existing relays have been in service for 20 plus years. Spare parts and replacements are difficult to impossible to obtain and the relays are not supported by vendors. Newer relays provide improved protection and alarming features which reduces the risk of failure. SEL Series 100 line relays do not meet NERC Standard PRC-023-1. SEL Series 100 PRTU Communication Port Switch relays do not meet NERC cyber security standards.

Digital Fault Recorders (DFRs) Replacement Program

Description: Replace first generation microprocessors based DFRs and begin a routine replacement program for current standard DFRs to avoid future obsolescence.

Key Drivers:

- Equipment end of life
- Equipment obsolescence
- Spare parts availability

- NERC, WECC and FERC Standards

Issues Being Addressed: Rochester (RIS) DFRs are a first generation microprocessor based DFR. They have a higher than normal failure rate and require excess maintenance. RIS DFR's were installed starting in 1985 to 1993 in BPA's main grid 500 kV stations and 230 kV stations where fault and disturbance recording are required. These systems are failing to run and record faults. Critical information for post disturbance analysis is not available. The primary failure is the drive memory. These drives use the unsupported Bernoulli 20 megabyte cartridge available only from salvage stores as located on eBay. Other parts for these devices are not available from the vendor and we can only support the existing units with salvaged parts. BPA must replace these recorders to comply with the WECC and NERC standards.

Ben DFRs are our current standard. By FY2012 we expect many components of these to be obsolete and not supported by vendors.

Sequential Event Recorders (SERs) Replacement Program

Description: Replace first generation Beta SERs.

Key Drivers:
- Equipment end of life
- Equipment obsolescence
- Spare parts availability
- Maintenance costs
- NERC, WECC and FERC Standards

Issues Being Addressed: These SERs are at or near their expected end of useful life. The devices are no longer supported by the vendor. WECC is establishing numerous standards for event recorders including location requirements, maintenance, monitoring, and data archiving requirements. BPA must replace these recorders to comply with the WECC and NERC standards. A dual function device will provide the SER function and the SCADA RTU function. Replacements of the SERs will be coordinated with the replacement of the SCADA RTUs.

Meter Replacement Program

Description: Replace Scientific Columbus JEM and RMS Meters. Approximately 900 units will require replacement over several years. We recommend replacing approximately 100 units per year.

Key Drivers:

- Equipment obsolescence and end of life
- Expanded need for metering data by BPA and customers

Issues Being Addressed: BPA began installing electronic JEM meters and Sentry 100 data recorders in the early 1980s. These meters are at or near their expected end of useful life. The devices are no longer supported by the vendor. Additionally, BPA billing, scheduling, and customers are requesting additional meter functions which are not supported by these meters. New devices will support faster and more frequent access to revenue data.

3.2.4 Communication and Control Assets

This Communication and Control asset plan is based on a comprehensive review and assessment that was completed in 2007 of the communication and control equipment assets, including age and health demographics and risk assessment to BPA's business and mission critical success. In addition, the plan will recommend an appropriate investment level to mitigate known or suspected risks to BPA's long term strategic objectives. Aging, for this effort, is defined as the deterioration over time of critical equipment or a component's mechanical, electrical, or thermal performance capabilities significantly increasing the risk of failure. Aging also includes critical component obsolescence resulting in the inability to initiate a timely response to component failures threatening system integrity and/or electrical service continuity.

3.2.4.1 Communication and Control Asset: Overview

BPA operates an extensive telecommunications and control system vital for the safe and reliable operation of the transmission system. The telecommunications system covers BPA's 300,000 square mile service territory in the Pacific Northwest utilizing a mix of technologies. A variety of control systems is utilized to provide high-speed clearing of power line faults, automatic response to changing system conditions, and visibility and control of substation equipment by dispatch. Together these systems provide the data and controls necessary to maximize transfer capacity and stability of the transmission system.

The majority of control data utilized to manage the operation of the transmission system is carried over a combination of a point-to-point analog microwave system and a digital microwave and fiber optic system. Together these systems are designed to provide a highly reliable and available system, and are an integral component of high-speed protective relaying, Remedial Action Schemes, SCADA, and generation dispatch systems. The telecommunications system also provides a reliable means of voice communications between Substation Operators, maintenance crews, and BPA Dispatchers. Both microwave and fiber optic systems are interconnected with similar systems for neighboring utilities and control area operators for exchange of control, data, and voice information. While its primary purpose is for transmission system operation, protection and control, the telecommunications system also provides a highly reliable network for internal administrative security, voice and data traffic.

Control systems provide the means for Dispatch to monitor the condition of the system and respond to changing conditions. Through a combination of automated and Dispatch-initiated control actions, BPA is able to respond quickly to power system events across the Pacific NW.

Spares
System reliability requires the right spares to be available in stock per BPA's Reliability Criteria and Standards. Transmission Services has initiated a program to review both its spares inventory and Emergency Minimum Stock (EMS) to assess their adequacy and establish both short and long-term stocking levels.

3.2.4.2 Communication and Control Assets: Age Demographics and Assessment

The chart in figure 1 shows the age demographics of several major classes of equipment. As can be seen, a significant amount of all our communication and control equipment is beyond 20 years of age, stretching to 45 years of age.

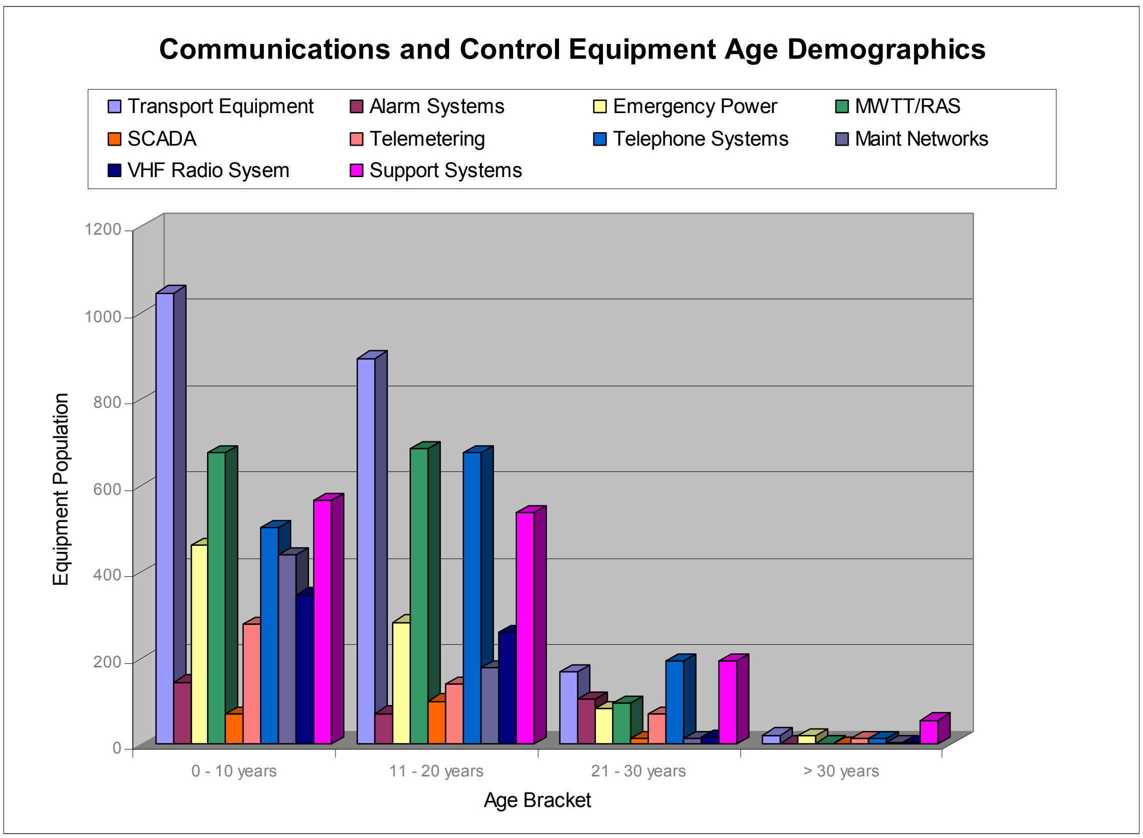


Figure 1

3.2.4.3 Communication and Control Asset: Health Demographics and Assessment

The Communications and Control Equipment asset is a vast and complex network of geographically dispersed components of widely varying age and technology and hence is truly difficult to characterize as an overall entity. In order to build a quantitative evaluation of the asset's overall health, the equipment groups are separated into major components organized by common related attributes.

It is reasonable to anticipate that major communication and control components will age at different rates necessitating risk management and assessment strategies tailored to the characteristics of each major communication and control component. Hence, the major critical communication and control components are grouped and identified as populations which facilitate efficient health assessment and risk management organization dependent on 1) their criticality to system performance, 2) aging related characteristics, 3) concerns for obsolescence, and 4) sub-component connectivity.

Transmission Services' strategy for Communication and Control equipment replacement changed from a programmed approach about 14 years ago, to a "just in time" approach. This approach has postponed replacement of aged and obsolete equipment, in most cases beyond its serviceable life due to lack of spare parts and OEM support.

All Communication and Control equipment is subjected to a time based Reliability Centered Maintenance (RCM) program, where different performance acceptance criteria are established for different equipment classes, and various inspection and testing techniques are employed to ensure the equipment continues to provide reliable service. Whenever a problem develops or is detected, a corrective action is initiated.

This Communication and Control asset plan has identified 10 major critical component categories organized utilizing the four basic criteria discussed above as listed in the table 1 below.

Overall Component Health Demographics

Major Component	Physical Condition			Obsolescence			Remaining Life			Asset Health
	Good	Fair	Poor	Good	Fair	Poor	<20	15-10	< 10	
Transport										Fair
Alarm Systems										Impaired
Emergency Power										Fair
MWTT/RAS										Impaired
SCADA										Impaired
Telemeter										Fair
Telephone										Impaired
Maint. Network										Impaired
VHF System										Poor
Support Systems										Fair

Table 1

Transport Equipment

Transport equipment includes all analog and digital microwave and UHF radios, interconnecting equipment, multiplex, and other supporting systems; fiber optic terminal equipment, digital multiplex, timing, and other supporting systems; powerline carrier systems; dedicated leased commercial telephone lines. The purpose of Transport Equipment is to move data and voice signals between locations.

The Analog Radio system is over twenty years old and starting to fail at certain component levels. Due to the age of the equipment, vendor support and spare parts are no longer available. The radios will continue to experience increasing failures and degradation of performance over time resulting in increasing impacts to the stability of the power grid as critical circuits are lost.

Alarm Systems

The Telecommunications Alarm and Network Management Systems provide visibility of equipment operating conditions at all communications installations across the system. Alarm information collected includes condition of radio and fiber terminals, associated multiplex and telephone equipment, emergency power systems, entry alarms at dedicated communications facilities, temperature alarms, and special circumstance alarms at a given site.

Emergency Power

Emergency Power includes communications batteries, chargers, engine generators, inverters, DC-DC converters, and UPS units. Emergency Power equipment is installed at all communications installations to assure continued operation of telecommunications equipment. Communications emergency power systems are separate from substation emergency power.

Battery maintenance has recently been identified as a requirement under the NERC PRC Protective Relaying reliability standards. BPA has identified both substation and communications batteries as requiring maintenance reporting. All batteries supporting sites that carry traffic from any site with transfer trip or other relay scheme that utilizes the telecommunications system are identified as having required maintenance tracking under the NERC PRC standards.

MWTT/RAS

Microwave and Fiber Optic Transfer Trip equipment is used for both high-speed relaying and Remedial Action Schemes. High-speed relaying allows for clearing of a line quickly for protection of the public and of substation and generator equipment. RAS schemes allow for automated response to system events to maintain power system stability and maximize transfer capacity. The use of these types of control schemes allows BPA to more fully utilize existing power line infrastructure. Currently there are over 1500 tone shelves installed on the BPA system.

BPA is highly dependent on RAS to maximize operational transfer capability (OTC) of the transmission system. Loss of a RAS scheme can have a significant impact on OTC and result in curtailments of as much as 3300 MW. WECC and NERC provide design and operational performance criteria for protective relaying applications that also apply to transfer trip.

WECC and NERC PRC standards for protective relaying also address transfer trip tone equipment maintenance. BPA has a maintenance program identified and a means for tracking and reporting completions. In addition, certain types of failures or misoperations are reportable to WECC/NERC.

SCADA/Supervisory/Telemetering

Supervisory Control and Data Acquisition (SCADA) systems are the primary means for Dispatch to monitor and operate the power system. SCADA Remote Terminal Units (RTU) in the substations collect data on the condition of substations, power system equipment and power lines and transmit this information to Dispatch. Dispatchers are able to perform remote operations of breakers, switches and transformers via the SCADA control features. This monitor and control capability allows for fast and efficient operation and response to changing system conditions. Field staffing of Substation Operators is predicated on the availability of SCADA to provide primary operation of the main and secondary power grids.

BPA currently has over 200 SCADA RTUs installed at substations across the northwest. The oldest model of SCADA is approaching 30 years of age. These units cannot be expanded or upgraded. The number of spares decreases as cards are cannibalized to restore service to failed units. As BPA attempts to move to more flexible and robust SCADA communication protocols, these remotes are one of the major obstacles to fully implementing a master upgrade.

Telephone Equipment

BPA maintains an extensive internal Dial Automatic Telephone System (DATS) for daily operation and maintenance activities. This is a highly available and reliable telephone system providing voice communications to Dispatch and field maintenance crews across the system. Additionally, there are DATS connections to interconnected customer utilities and generators. This system is designed to provide a level of reliability that cannot be guaranteed by commercial services and to provide service at remote sites where commercial services are not available.

Most BPA sites have commercial service in addition to DATS to be used for voice and data communications. Generally, BPA maintenance and operations personnel rely on DATS for their primary voice service as it is the most reliable means of communications.

<u>Maintenance Network</u>
Over the last several years BPA has installed large numbers of relaying and substation monitoring devices that are capable of remote communications access. This has created a need for secure communications to these devices for the collection of fault data and access to verify and update settings. Remote access has saved significant amounts of travel time for staff in not having to drive to sites to collect data. As the number of intelligent devices increases, the demand for remote access also increases. NERC has imposed new regulations for the protection of Critical Cyber Assets in substations, thereby creating additional importance for the availability of an internal network to provide secure remote access to critical substation devices.

<u>VHF System</u>
The VHF system provides mobile communications for maintenance crews and Dispatch across the system. The VHF system was designed to provide reliable voice communications to as much of the system as possible. The primary use is for switching and line work. Many parts of the power system have no other means of communications from power line rights-of-way. This is a critical system for line operation, restoration, and crew safety.

The system covers BPA's service territory and serves approximately 1,500 mobiles and portable handsets through a VHF/UHF system with 67 repeater sites linked to the microwave network. Government mandated narrow banding of the VHF and UHF radio networks to improve spectrum efficiency as well as additional Department of Homeland Security requirements will require additional upgrades to the network.

Like the analog microwave system, the mobile radio system has reached its end of life cycle. Manufacturer support is not available and spare parts are becoming more difficult to obtain. The system also does not provide some of the needed functionality that is being requested by the end users.

<u>Miscellaneous Support Systems</u>
This category includes systems such as public address systems at maintenance facilities, GPS timing and power line fault location.

GPS provides accurate timing signals to end equipment for precise time-tagging of events and system coordination. Many of the GPS units also provide fault location functions and are rapidly replacing older fault locater remote units.

PA systems are an important tool for safety and communication within facilities. Alert tones indicating remote equipment operation, voice warnings of impending actions and crew paging are a few of the services provided by PA systems at substations.

3.2.4.4 Communication and Control Asset: Risk Assessment to Operating System

Staffing

The ratio of experienced craftsmen and field engineers to trainees has shifted in the last 10 years to a much higher percentage of newer people. Some of the legacy systems could be in jeopardy if the experienced staff leave and newer staff haven't been adequately trained to maintain the older systems. Most trainee applicants have no experience with analog communications for instance, creating a steep learning curve on a vital part of the overall system. At the same time as equipment volume and complexity have been going up, the number of fully trained maintenance staff has been going down.

The impact of the combination of increased equipment count, equipment variety, and decreasing trained staff has resulted in a lowering of the overall health of the communications and control equipment system wide. With greater demands and fewer people, lower priority tasks that might extend or improve equipment performance have fallen by the wayside. Collection and centralization of data is not completed beyond the essentials required for the districts to function. Maintenance data is not always available outside of the facility where the equipment is located. Accurate inventories of equipment models, revisions, installation and test data are not available. The data is adequate for a high level summary but not a good quality analysis of equipment health.

Communication and Control Asset

Equipment risk assessment is summarized on Figure 2 plotting System Impacts against Component Health providing a measure of a component's overall health in terms of physical health, obsolescence, and remaining life against potential operational impacts to system reliability and asset availability. The plot is organized into essentially five regions from High Risk in the upper right corner to Low Risk in the lower left corner.

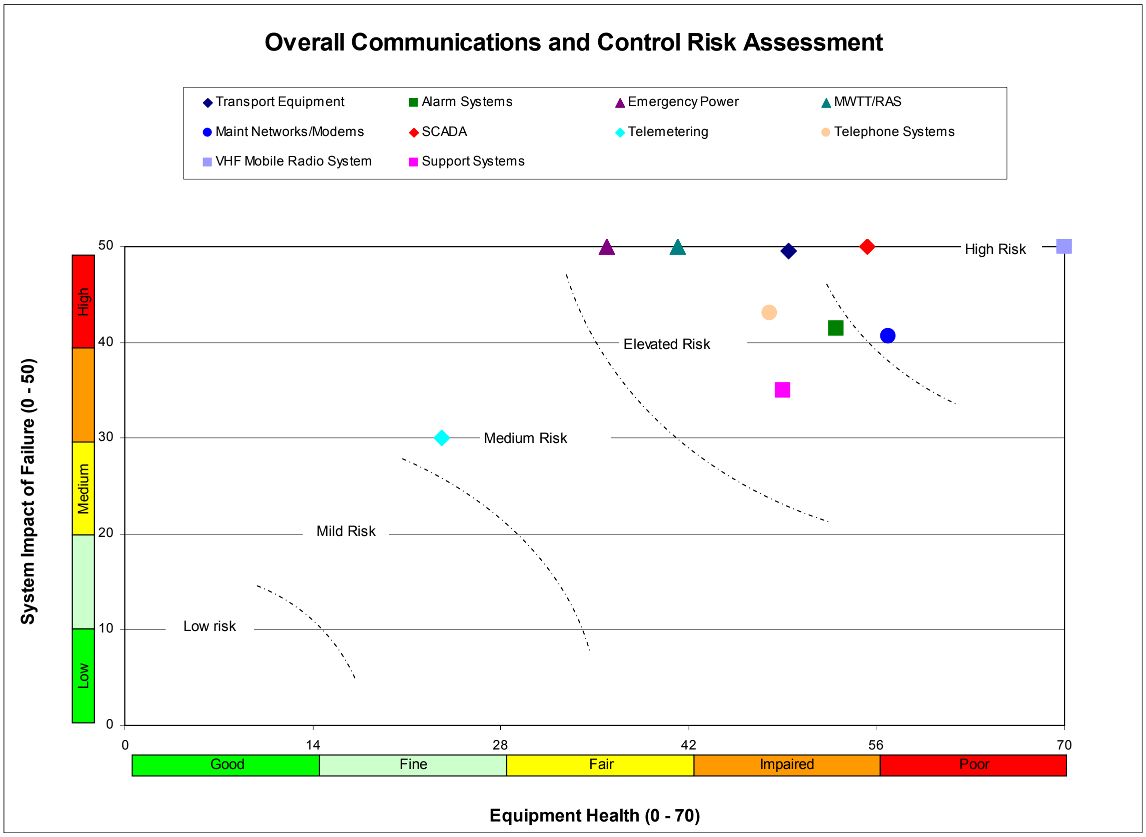


Figure 2
High level summary of communications and control equipment risk assessment

3.2.4.5 Communication and Control: Recommendations and Future State

Based on the overall health and risk assessment, this Communication and Control asset plan has a number of recommendations for consideration by management. In order to meet Agency and Transmission Services strategic long term outcomes, a characterization of a Future State for all major components of the Communication and Control asset has resulted in a number of strong inferences which naturally gravitate into recommendations for action. The fundamental goals and drivers for these recommendations are focused on 1) improving the overall health of the installed Communication and Control assets to a Good status to ensure its continued success and 2) provide proactive processes to manage and assess the Communication and Control asset as it continues to age to demographic levels which BPA has little or no experience managing and mitigating. As these goals and drivers are common across the industry both locally and globally, a more proactive strategy and approach requires development in order to have adequate assurance of success. Inadequate or improper management, assessment, or mitigation processes inconsistent with the new challenges of a significantly aged Communication and Control asset can easily result in gross loss of reliability and/or availability threatening the very mission and business success of BPA and its stewardship of the Region it serves.

The Communication and Control asset plan recommendations essentially fall into four groupings addressing the goals and drivers discussed above. The groupings are;

- Aggressively pursue an active replacement program for five programs identified as being in poor health or obsolete
    1. Analog Radio System Replacements supported by Circuit Moves from Analog to Digital
    2. VHF Mobile Radio System Replacements
    3. Transfer Trip and RAS Tone Equipment Replacements
    4. SCADA/Supervisory Control/Telemetering Replacements
    5. Badger Alarm System

- Continue to characterize and assess the Communication and Control asset at an adequately granular level both temporarily and spatially to facilitate proper proactive management.
- Continue to develop the Transmission Services' Asset Information System (TAS)
- Continue to develop and improve documented strategies to better manage and mitigate the adverse effects of aging, or age related degradation processes, in a manner which ensures the continued success of the reliability and availability of the overhead asset.

While we have collected known demographic data on these assets, there are many inconsistencies and inadequacies with present processes and demographic data, in meeting our goal of being PAS-55 compliant by 2010. Using a reactive strategy with minimal quality data, which has served BPA in the past, will be grossly inadequate as the assets age into the future.

3.2.4.6 Investment Recommendations

Fiber Optic Cable Maintenance

- Priority Rating: Mandatory

Description: There is presently no on-going sustained capital program identified for the Fiber Optic Cable. However, last year several capital projects were approved for repair and/or maintenance of the fiber cable. It is expected that an on-going capital program will be necessary to replace and upgrade as the cable ages and deterioration begins on the cable as well as the supporting hardware, and capacity increases are required. The PSC maintenance program will focus on the testing of the glass within each of the cables and aid in determining health of the cable and locating damage. The maintenance of the outer cable will be covered under the Line Maintenance Section. The implementation of a yearly program could prevent some of the problems experienced in the past.

Key Drivers:
- Preventive projects to prevent outages on the fiber cable.

Issues Being Addressed: Help to locate damage to the fiber glass. This could aid in the location of abrasion issues on the cable, areas of icing which require reinforcement of the cable, vandalism locations where cable may need to be relocated.

Analog Radio System Replacements
- Priority Rating: Mandatory

Description: Replacement of selected fixed-link radio networks (UHF and microwave) with new digital systems to increase telecommunication capacity and to reduce instances of age related equipment failures. Primary areas of build out are the Puget Area and Oregon southern digital loop. Projects are at various locations on the system.

Key Drivers:
- Equipment operability
- Equipment end of life

Issues Being Addressed: Increasing unreliability of obsolete analog equipment.
- Lack of vendor support
- Unavailability of components to effect module repairs
- Increased capacity requirements

Program Management: This is a recurring program. Projects are prioritized based on several factors including the risk of failure, and the impact of system operation and reliability.

Communication Sites
- Priority Rating: Mandatory

Description: Replace end-of life, discontinued or unserviceable equipment (emergency power supplies, air conditioners, monitoring systems, etc.) at selected repeater sites.

Key Drivers:

- Equipment operability
- System reliability
- Equipment capacity

Issues Being Addressed: An uninterruptible source of power is critical at microwave repeater sites. At BPA, this is usually accomplished by installing station batteries and an emergency generator. New equipment additions and upgrades at microwave stations may require a larger generator and/or battery plant to support the load.

Repeater sites also require adequate cooling capacity. When equipment rooms overheat, the communication equipment is put at risk of improper operation or failure. A disabled microwave site will lead to a loss of control and telemetry for transmission circuits served by the microwave site.

Program Management: This is a recurring program. Projects are prioritized based on several factors including the risk of failure, and the impacts on system operation and reliability.

Future Fiber Optics

- Priority Rating: Mandatory

Description: This program provides fiber optic installations where needs are identified. The fiber optic cables provide communication linkage with substation controls and data acquisition systems. The majority of the funding for FY08 through FY12 is for the Puget Area fiber build out.

Key Drivers:

- Equipment obsolescence
- System reliability
- Safe operation of the power system

Issues Being Addressed:

- Existing equipment reaching end of life.
- Limited capacity
- No manufacturer support.

Program Management: This is a recurring program as the fiber system is built out to provide required telecommunication services for Operations

Unidentified Telecom Upgrades

- Priority Rating: Mandatory

Description: Unidentified telecommunication upgrades that will address communication site and system needs such as reliability, security, and NERC requirements.

Key Drivers:
- NERC and WECC requirements

Issues Being Addressed:
- Compliance with NERC and WECC reliability standards

Program Management: This is a recurring program

Minor Telecom
- Priority Rating: Mandatory

Description: Upgrade to the DATS system and PACI RAS Upgrade (PG&E Control Center)

Key Drivers:
- Upgrade the capabilities of the DATS network
- RAS upgrade with PG&E

Program Management: This is a recurring program. The specific projects identified in the description will be completed by FY10.

VHF Mobile Radio System Replacement
- Priority Rating: Mandatory

Description: Replacement of the existing VHF Mobile Radio System.

Key Drivers:
- Equipment obsolescence
- System reliability
- No manufacturer support

Issues Being Addressed:
- o Existing equipment reaching end of life.
- o No manufacturer support for the existing hardware.

Program Management: This is a recurring program over a six year period.

Circuit Moves
- Priority Rating: Mandatory

Description: Relocation of the circuits from the analog system to the digital network.

Key Drivers:
- Equipment obsolescence of the analog system
- System reliability
- No manufacturer support of the analog system

Issues Being Addressed:
- Existing analog equipment reaching end of life.
- No manufacturer support for the existing hardware.

Program Management: This is a recurring program over a six year period.

3G Replacement
- Priority Rating: Mandatory

Description: This project is being funded by appropriated funds under the frequency auction of the 1710-1755 MHz Frequency Relocation project. No capital dollars are required but BPA FTE will be used to complete the design and installation work for this project.

The removal of the 1710 frequencies requires BPA to construct alternative paths for the communication traffic. This project replaces those MW hops with a combination of digital radio and fiber optics.

Key Drivers:
- BPA required by DOE to vacate frequencies
- Timeline established by NTIA and DOE
- Appropriated funds that are designated by timeline established for replacement sites

Issues Being Addressed: Replacement of the 1710-1755 MHz radio hops as required by DOE.

Program Management: This is a reoccurring program over a five year period.

SCADA Replacements
- Priority Rating: Mandatory

Description: Replacement of obsolete SCADA remote terminals. Currently only three replacements are funded in the FY08-FY09 funding cycle. In order to maintain an orderly replacement of aging equipment, recommend replacing 10 remotes every year in an ongoing program.

Key Drivers:

- Equipment obsolescence
- System reliability
- No manufacturer support
- Lack of flexibility for expansion, modification

Issues Being Addressed: Oldest units have reached the end of their useful life and are operating on borrowed time. No manufacturer support for oldest units, and expect to lose support for remaining equipment in less than 5 years time.

Program Management: This is a recurring program.

Transfer Trip Replacements

- Priority Rating: Mandatory

Description: Replacement of obsolete transfer trip tone equipment. Currently only 8 replacements are funded in the FY08-FY09 funding cycle. In order to maintain an orderly replacement of aging equipment, recommend replacing 80 to 90 tone sets every year in an ongoing program.

Key Drivers:

- Equipment obsolescence
- System reliability
- No manufacturer support
- Incompatible with digital communications

Issues Being Addressed: Oldest units have reached the end of their useful life and are operating on borrowed time. No manufacturer support or components available for oldest units. Analog equipment is susceptible to misoperation on digital circuits due to technology mismatch.

Program Management: This is a recurring program.

Emergency Power Equipment Replacements

- Priority Rating: Mandatory

Description: Replacement of failing batteries, chargers, engine generators, DC-DC converters and inverters. Currently only 4 replacements are funded in the FY08-FY09 funding cycle. In order to maintain an orderly replacement of aging equipment, recommend replacing an average of 30 battery plants, 20 chargers, 3 DC-DC converters, 3 UPS systems, and 4 engine generators every year in an ongoing program.

Key Drivers:

- Equipment obsolescence
- System reliability
- No manufacturer support

Issues Being Addressed: Oldest units have reached the end of their useful life and are operating on borrowed time. No manufacturer support or components available for oldest units.

Program Management: This is a recurring program.

Alarm System Replacements

- Priority Rating: Mandatory

Description:
Replace failing Badger alarm remotes within next five years. Establish a recurring replacement program for alarm system remotes to maintain reliable system operation.

Key Drivers:

- Equipment obsolescence
- No manufacturer support
- Inability to purchase components to make board repairs
- NERC COM-001 requirement to monitor and alarm communications system.

Issues Being Addressed: The Badger system has reached the end of its useful life and is operating on borrowed time. No manufacturer support is available. Aging components and incompatible substitute components have created a situation where a complete rebuild of the board is required for any functionality, and proper operation of repaired boards cannot be adequately tested due to interactions between rebuilt boards and the test jigs used in the testing process. Some components must be cannibalized from retired boards.

Program Management: This is a recurring program.

Telephone Systems

- Priority Rating: Mandatory

Description: Replacement of obsolete key telephone equipment and telephone protection systems.

Key Drivers:

- Equipment obsolescence

- System reliability
- No manufacturer support
- Personnel safety

Issues Being Addressed: Need to replace obsolete key telephone systems installed from 1966 on. No manufacturer support or components available for oldest units.

Program Management: This is a recurring program.

Maintenance Networks

- Priority Rating: Mandatory

Description: Replacement of obsolete or inadequate equipment with equipment capable of supporting network operational requirements and utilizing acceptable network security technologies to support NERC-CIP reliability standards.

Key Drivers:

- Equipment obsolescence
- System reliability
- No manufacturer support
- Technology changes
- Network security requirements

Issues Being Addressed: Units need to be replaced when they are not able to support network functionality and security requirements or are no longer supported by the manufacturer.

Program Management: This is a recurring program.

Miscellaneous Support Equipment

- Priority Rating: Mandatory

Description: Replacement of obsolete and failing equipment. Systems in this asset grouping primarily support major control systems and maintenance personnel and include PA and annunciator systems for crew safety and work efficiency; GPS timing applications; power line fault location.

Key Drivers:

- Equipment obsolescence
- System reliability
- No manufacturer support

Issues Being Addressed: Oldest units have reached the end of their useful life and are operating on borrowed time. No manufacturer support or components available for oldest units. Incompatible technologies.

Program Management: This is a recurring program.

3.2.5 Control Centers

BPA's Control Centers were built to provide secure and highly available dispatch locations, infrastructure, systems and tools to support the safe and reliable control and operation of the Northwest power system. In support of power system control and operation, the centralized systems and tools also provide real-time monitoring, analysis and simulation. The control centers are located to provide geographically separate hot standby redundancy for critical operations and control functions. Munro also hosts backup infrastructure for BPA's critical business systems. BPA's communications infrastructure and remote control and monitoring equipment in the substations enable the centralized functions of the control center.

Many of the control center systems facilitate increased system utilization (Non-Wires Solution) and reduction of operational staff in the field. Monitoring and alarm systems increase the power system Mean Time Between Failure (MTBF) and decrease the Mean Time To Repair (MTTR). Failure of systems such as RAS, SCADA and AGC would cause the immediate derating of the power system and resultant revenue loss.

BPA has two control centers.

Historical Perspective

BPA's Dittmer Control Center (DCC) was energized in 1974 prior to the advent of modern computing and networking technology. At that time all critical 7x24 systems were in the DCC. BPA was an early adopter of Grid Operations automation. It has a high quality set of real-time control and analysis tools. However, due to its long evolution and dependence on expensive and sometimes custom system wide infrastructure, the control center systems are not as well integrated and streamlined as desired.

The BPA microwave and fiber optic communication infrastructure has been implemented largely in support of the centralized monitoring and control functions at the control centers. Remote equipment in BPA's substations and control center equipment often have to be updated concurrently to insure compatibility. This can add significantly to the cost and schedule of system replacements.

In the late 80's it was determined to be critical that BPA have redundant control centers, each with independent telecommunication systems, to provide the necessary high availability and backup for critical grid operation systems and their users. This need spurred the building of Munro Control Center (MCC) in 1996. MCC serves as an alternate control center for the most critical grid operation applications (primarily SCADA, RAS and AGC). The movement of additional grid operation systems to the alternate control center has been discussed but many projects have been deferred due to funding and resource limitations.

Up until the early 90's there were only two major real-time systems (RODS and SCADA) and a number of minor grid operations systems at DCC. As a result of the 1996 FERC Order No. 888 and 889 requiring open access to transmission networks, Transmission and Power Services were formed and the TS and PS separation occurred. Since this time there has been a significant increase in the number of critical business systems to support new and expanding business processes, many of these require 7x24 operations. There is a broad spectrum of 7x24 needs based on tolerable Mean Time To Repair (MTTR). Recent Continuity of Operations (COOP) planning efforts have increased the focus on the use of BPA's control centers for backup of a broad spectrum of systems.

The technical support of the critical business systems (CBS) has been centralized in the J organization. To align the CBS technology, infrastructure and support organizations, projects have been initiated to move CBS out of DCC into a nearby high reliability data center facility and to implement backups at MCC on an infrastructure separate from the control and operations infrastructure. This separation is due to the differing missions and technical nature of the systems, infrastructures, maintainers and users. Other than the CBS use of the MCC basic infrastructure of power and HVAC, the CBS are not considered part of the Control Center Asset category for planning purposes.

Control Center Asset Plan Logic and Scope

The Scope of the CC asset plan covers all systems within the control center that are essential to power system operations and control, or are tightly coupled or provide critical support to these systems.

Exceptions to the scope include the control center telecommunications infrastructure which are covered in the PSC equipment group and the general purpose or critical business systems in the control center but maintained by the Agency IT organization on a separate Critical Business System network infrastructure.

To meet NERC CIP regulations and for general cyber security reasons there is a tight cyber security boundary around the control center systems that are essential to the operation of BPA's power system assets.

Projects will be initiated to maintain or improve the capability and reliability of the Control Center systems. Power system availability is directly related to control center systems availability.

It is the goal of the control center systems is to continually improve the reliability and availability of the power system resources through the improved operational planning, monitoring, control and analysis capability by the application of automated tools.

3.2.5.1 Summary of Critical Control Center Assets

Control Center Systems and Applications

- **Major Control Center Systems – MCS - (DCC & MCC)**
  - **SCADA Master Systems** (DCC & MCC) – Supervisory Control and Data Acquisition Systems provide remote monitoring and control of power system equipment. Primary and backup systems at both control centers.
  - **Automatic Generation Control Systems** (DCC & MCC) – AGC provides the closed loop control of federal hydro generation to meet load.
  - **AC Remedial Action Scheme Masters** (DCC & MCC) - RAS Masters facilitate automatic control actions to deal instantaneously with system events. RAS actions maintain system stability.
  - **Power System Security Tools (PSST)** (DCC) – PSST tools allow the mathematical simulation of planned system actions to determine the potential impact on the stability and reliability of the power system. The system uses a model of the real-time state of the power system based on real-time SCADA measurements and measurements and other information received from adjoining utilities. Major PSST components include State Estimator, Contingency Model, Power System Model and Voltage Stability Analysis.

- **EMS Support Infrastructure – ASI -** (DCC & MCC)
  - SCADA ICCP
  - Gen ICCP
  - Web Full Graphics
  - SCADA Front-ends

- **Dispatch Training System - DTS -** (DCC)
  - Power System Model
  - SCADA Clone
  - AGC Clone
  - PSST Clone

- **Monitoring and Alarm Systems - MAS -** (DCC and/or MCC) **–** Below are some of the more prominent Monitoring and Alarm Systems.
  - Sequential Events Monitor Master (DCC)
  - Fault Locator Master (DCC)
  - KWH Master (DCC)
  - Network Management System (DCC &MCC)

- Badger Master (DCC)
- Microwave Monitor Master (DCC)

- **Misc. CC Tools and Data Systems - MTD** (DCC and/or MCC)

    - **PI System** – The PI system provides specialized data archiving and presentation optimized for time series data. The PI system primarily deals with SCADA and AGC data.
    - **Real-time Operations, Dispatch and Scheduling (RODS) System** (DCC) – RODS is a multi-application legacy mainframe system that originally hosted AGC and PSST but is in the process of being retired. Below are some of the more significant applications remaining on RODS.

        - CSM Alarms
        - Curtailment Calculators (Legacy)
        - Field Callout Lists
        - Numbers Program (Energy Accounting)
        - Transmission Scheduling Rotary Accounts
        - Transmission and Power Services Data Messaging and Processing

- **Dispatch Logging Systems (to be replaced by DART)**
- **OPI (SHIP, OARS, Dispatch Log Search, DSO Electronic Access)?** The OPI tools reside on the CCN DMZ and are primarily accessed via the general purpose network. As the tools become more critical a dispatch access path may be created from the CCN proper.
- **Control System Monitor (CSM) Tools** –
- **Test and Development Infrastructure**
- **Relay Information Systems**
- **Critical Business Systems Support –** These are the infrastructure components required to support the interfaces from the control center systems to critical business systems and general purpose systems. These interfaces must be implemented to provide the highest level of security. Direct connection from systems external to the CCN is not allowed for security reasons.
- **Integrated Curtailment and Redispatch Tools –** A new suite of tools is being developed on a separate system to support the execution of curtailment and redispatch processes. These systems use capacity, loading, generation and scheduling information.

Control Center Infrastructure Components

- **Control Center Network (CCN) Infrastructure – CNI -** (DCC & MCC)
    - CCN Production Infrastructure
    - CCN Network Management Infrastructure
    - CCN Cyber Security Infrastructure

- **Control Center Server Infrastructure – CSI -** (DCC & MCC)
    - CCN Server Security Infrastructure
    - CCN Services Infrastructure
    - CCN Server Test/Simulation Infrastructure

- **Control Center User Interface Infrastructure – CUI -** (DCC & MCC)
    - CCN User Work Stations
    - Mapboards & Video Walls
    - Phone Systems –
    - Voice Recording Systems
    - CSM Displays and Infrastructure

- **Control Center Facility Infrastructure – CFI** – (DCC and MCC
    - CC Building Management Systems
    - CC Electrical Infrastructure
    - Timing Systems
    - Physical Security Systems

3.2.5.3 Control Center Assets: Health Demographics and Assessment

The control center systems and equipment have evolved over more than 30 years. Because of BPA's early adoption of operations and control automation, many of the older systems contain custom and often obsolete hardware and/or software. Systems are added and upgraded as the power system and associated processes require change and technology allows. Where possible, systems are also upgraded to stay current with vendor supported versions of their hardware and software.

The general health of control center systems which constitutes the risk event probability is judged on four factors.

- **Maintainability** – This is a measure of BPA's capability to maintain the asset. It is a reflection of the skill and depth of support staff, the adequacy of spares available from within BPA and the degree that vendor support is readily available as a second level of support.

- **Obsolescence** – This measure reflects the degree to which new hardware is available for replacement and upgrade, whether the hardware and software is interoperable with other standard technology and whether the software and hardware components are still supported by the vendor.

- **Flexibility and Expandability** – To what degree can functionality be added to the system or the functionality of the system changed to meet changing needs. To what degree can the system capacity and performance be increased to meet the needs of the expanding power system and increasing number of users?

- **Reliability** - Mean Time Between Failure (MTBF)

3.2.5.4 Control Center Assets: Risk Assessment

This section describes risk tolerance for the systems and processes of the control centers. In general, because of the real-time critical nature of grid operations, its risk tolerance is very low. For this reason, we may mitigate for lower probability risks than some other organization. Also, many Control Center risks, though low probability, will have very large impacts.

Control Center Risk Management Context

- System Operations is risk averse. There is no room for error, as outage and switching mistakes can have regional outage and life and death consequences, (critical safety issues for field employees).
- Keeping the lights on is our primary mission, all else, except safety, comes second.
- There is a high regional economic impact and political impact for major outages, system failures, operations and control errors.
- The region has a low tolerance for power system failure.

Power System Risks Associated with Systems and Processes

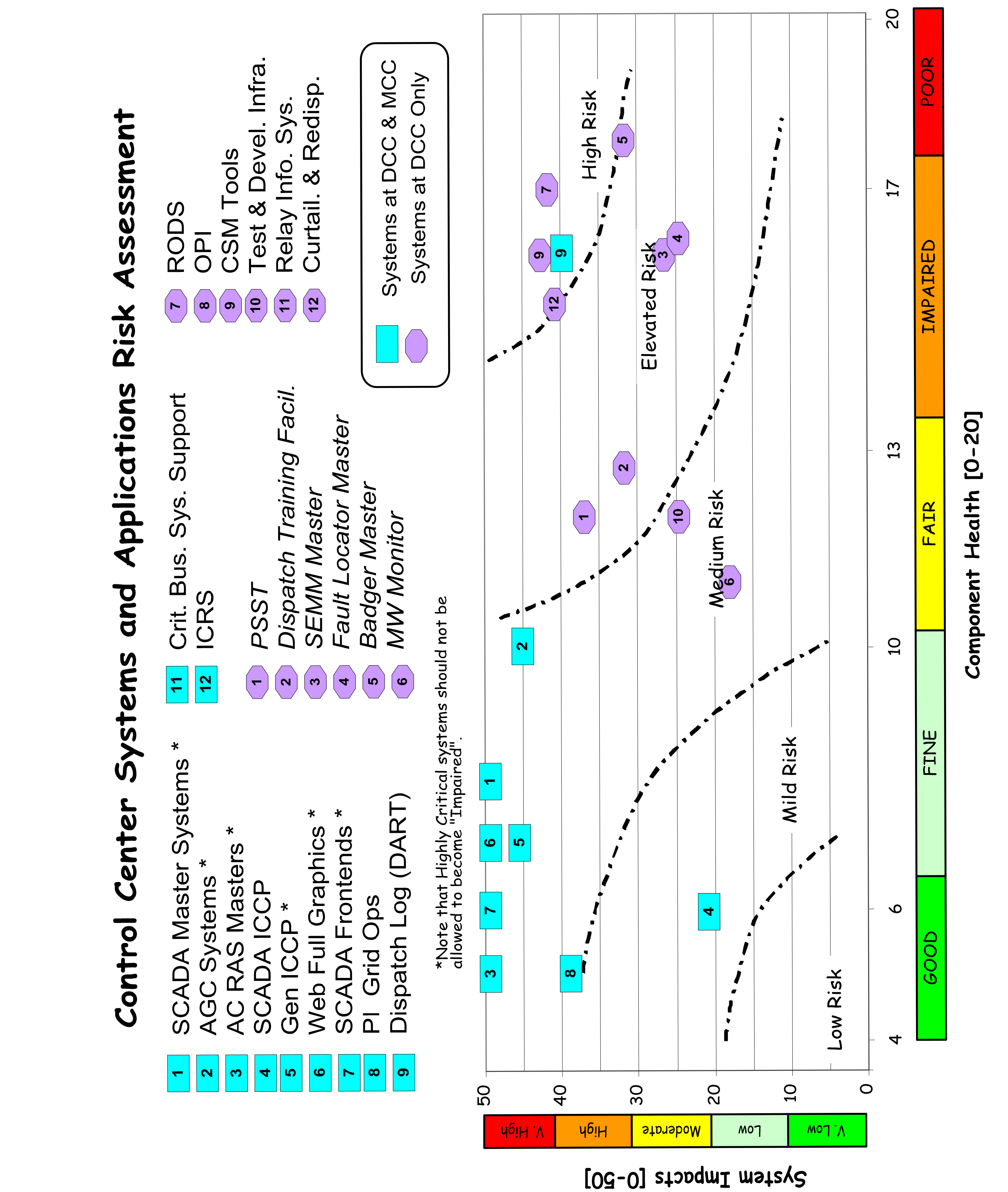
- Improper control center system or dispatcher action causes a power system outage.
- Improper or unavailable control center system or dispatcher action fails to prevent a power system outage.
- Improper dispatcher action fails to prevent a power system equipment failure (e.g. transformer equipment monitoring and/or overloading).
- Primary control center systems fail. These failures occur more frequently. The time to repair these failures takes longer. Failures go undetected for long period of time increasing system vulnerability.
- Lack of action by dispatcher or CSM or control center system failure causes more lengthy power system repair time.

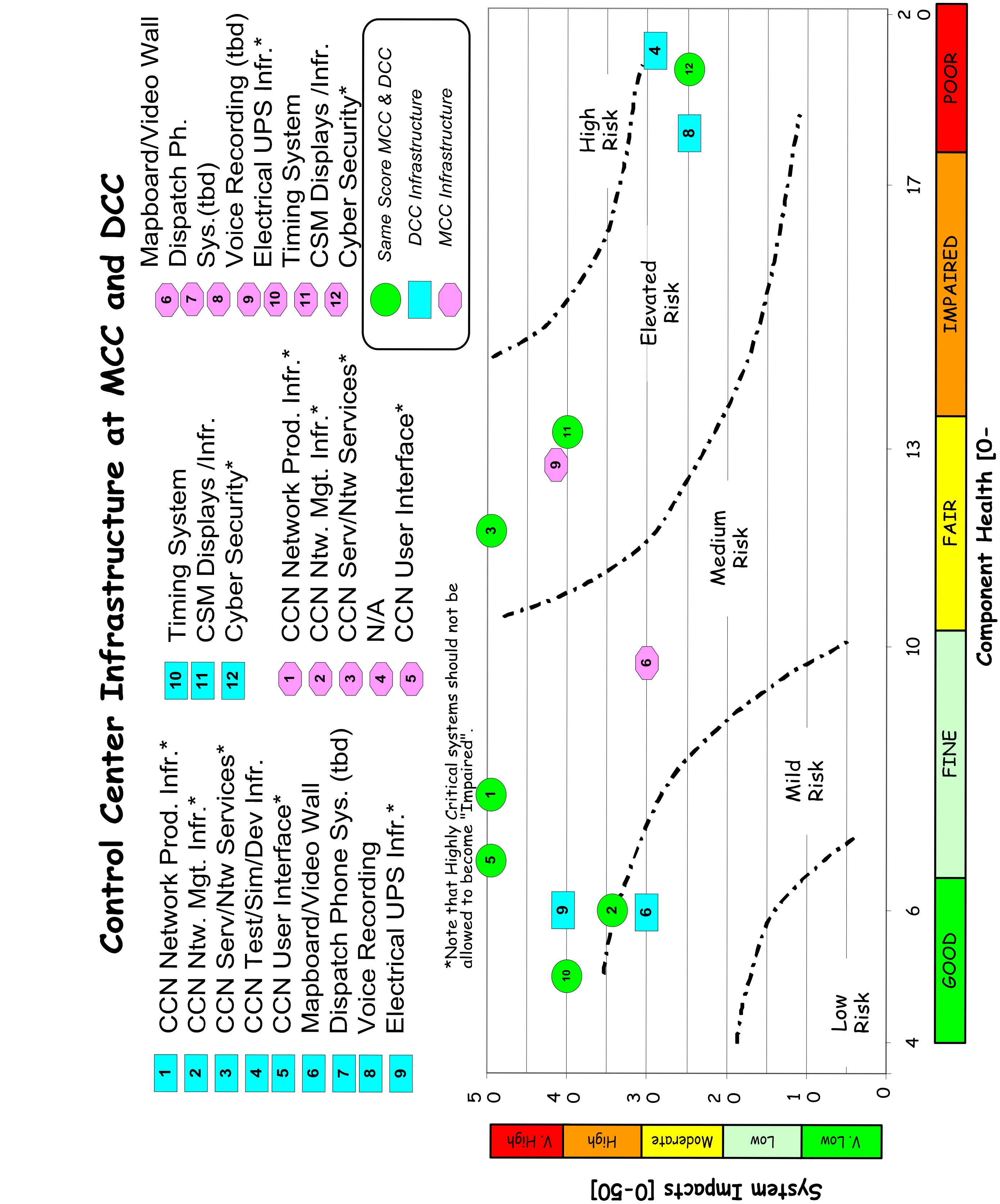
Risks Directly Impacting Control Center Facilities and Equipment

- Lack of a full set of systems at MCC diminishes the quality of dispatch service in the event of a failure of Dittmer. (COOP)

- Some CC systems consist of obsolete and unsupported hardware and/or software.
- The DCC and MCC are approximately 30 and 10 years old respectively and some of their infrastructure may be degraded.
- Technical support staff with critical knowledge are retiring.
- Aging staff are not well versed in the new technologies of new systems.
- Support staff growth has not kept pace with the growth in the number and complexity of new control center systems and tools.
- Support staffs are dependent on contractor staff in key technical positions.

(See the MCC & DCC Risk Assessment Charts on the following pages.)


Control Center Systems and Applications Risk Assessment
1 SCADA Master Systems *
2 AGC Systems *
3 AC RAS Masters *
4 SCADA ICCP
5 Gen ICCP *
6 Web Full Graphics *
7 SCADA Frontends *
8 PI Grid Ops
9 Dispatch Log (DART)
11 Crit. Bus. Sys. Support
12 ICRS
1 PSST
2 Dispatch Training Facil.
3 SEMM Master
4 Fault Locator Master
5 Badger Master
6 MW Monitor
7 RODS
8 OPI
9 CSM Tools
10 Test & Devel. Infra.
11 Relay Info. Sys.
12 Curtail. & Redisp.
Systems at DCC & MCC
Systems at DCC Only
*Note that Highly Critical systems should not be allowed to become "Impaired".
High Risk
Elevated Risk
Medium Risk
Mild Risk
Low Risk
System Impacts [0-50]
V. High
High
Moderate
Low
V. Low
50
40
30
20
10
0
4
6
10
13
17
20
GOOD
FINE
FAIR
IMPAIRED
POOR
Component Health [0-20]


Control Center Infrastructure at MCC and DCC
1 CCN Network Prod. Infr.*
2 CCN Ntw. Mgt. Infr.*
3 CCN Serv/Ntw Services*
4 CCN Test/Sim/Dev Infr.
5 CCN User Interface*
6 Mapboard/Video Wall
7 Dispatch Phone Sys. (tbd)
8 Voice Recording
9 Electrical UPS Infr.*
10 Timing System
11 CSM Displays /Infr.
12 Cyber Security*
1 CCN Network Prod. Infr.*
2 CCN Ntw. Mgt. Infr.*
3 CCN Serv/Ntw Services*
4 N/A
5 CCN User Interface*
6 Mapboard/Video Wall
7 Dispatch Ph. Sys.(tbd)
8 Voice Recording (tbd)
9 Electrical UPS Infr.*
10 Timing System
11 CSM Displays /Infr.
12 Cyber Security*
Same Score MCC & DCC
DCC Infrastructure
MCC Infrastructure
*Note that Highly Critical systems should not be allowed to become "Impaired".
Low Risk
Mild Risk
Medium Risk
Elevated Risk
High Risk
System Impacts [0-50]
V. Low
Low
Moderate
High
V. High
Component Health [0-20]
GOOD
FINE
FAIR
IMPAIRED
POOR

3.2.5.5 Control Center Investment Recommendations / Portfolio Management Process

TOSC - The control center project portfolio is managed by the **T**ransmission Services System **O**perations (TO) **S**teering **C**ommittee. The purpose of the TOSC is:

- To provide a comprehensive business and technical perspective in the management of the Control Center Grid Operations (GO) Capital Project Portfolio
- To insure that the projects that best support Grid Operations and Transmission Service's strategic objectives are selected and submitted.
- To insure that Grid Operations resources are applied to projects in a coordinated way to support most beneficial execution of Grid Operations projects.
- To provide improved, "as simple as possible" and repeatable project portfolio management processes and decision-making.
- To provide a visible and cohesive advocacy group for the GO project portfolio to the Asset Management Process.

The core members of the TOSC include the managers from within system operations organization and the control center planning office. To evaluate, compare and prioritize projects within or additions to the control center portfolio the TOSC uses the following criteria:

- Safety - This factor is related to the safety of BPA employees and others who work on or near the power system and its related support systems and infrastructure.
- Power System Reliability - This factor is related to transmission system outages, equipment failures, Mean Time To Repair/Recovery (MTTR) and Mean Time To Failure (MTTF).
- Other Business Strategy - This factor is a measure of how directly this project supports Transmission Service's and BPA's strategic objectives that are not directly reflected in the other evaluation criteria. Specific strategic objectives that are supported should be noted in the Comments field of the evaluation worksheet
- People, Processes and Systems (HPO) - This factor is a measure of the degree that the project directly supports improving processes and systems in support of people carrying out BPA's organizational obligations.
- Financial - Has a significant direct effect on; assurance of third party bonds, assurance of treasury payment, lowering risk of stranded investment, decreasing operating expenses and/or increasing revenues
- Regulatory, Legal, Political - Has a direct effect in bringing Transmission Services into NERC, FERC and/or WECC compliance in critical and high visibility areas; and/or has a direct effect in bringing Transmission Services into DOE, OMB and/or congressional compliance in critical and high visibility areas; and/or stems significant customer

pressure/criticism/complaints; and/or decreases likelihood of major legal challenges.

- Maintainability - This factor is related to equipment or systems that are being replaced or upgraded and ranks its maintainability. *(This is a combination of the Asset Health scores for Maintainability, Obsolescence, and Flexibility and Expandability.)*
- Other factors considered include critical project dependencies, project progress and project previous priority.

All project planning documents related to the planned and active control center projects are located on the Control Center Grid Operations Project website.

3.2.6 Tools & Equipment Acquisition Program (TEAP)

The Tools Equipment & Acquisition Program is an outgrowth of what originally started out as a yearly fixed funding program to purchase and replace large ticket tools and equipment. Regional Managers forwarded requests which were funded up to the established funding thresholds of the program, rather than by demonstrated need. At the request of Transmission Executives, beginning in 2003, a much more rigorous and structured program was put into place which requires a three strep review and approval process before Transmission endorses any request.

To fall into this program, each specific request must exceed $10,000. Items costing less than this amount are purchased with expense dollars. It should also be noted that the TEAP program does not handle rentals. Under this revised process, Regional Managers first gather, prioritize, review and approve all items requested. Once their list is finalized, it is forwarded to the TEAP Portfolio Team for review. This team, comprised of technical program managers from across transmission, rates and ranks all requests received for each fiscal year. Once the team's recommendations are finalized, an itemized list which details the organization, requester, item, number requested, priority rating and estimated costs, are forwarded to the Transmission Asset Management Council (T-AMC) for review and approval. It is this final T-AMC approved list which was submitted to the Agency Asset Management for review & approval.

Guidelines for this program reflect a strategy of maintaining equipment to meet its original design & function while also meeting employee safety objectives. When continued maintenance and repair of equipment is no longer feasible, plans to replace the equipment are developed that consider the unique circumstances of each case. Where similar equipment is used throughout the transmission system, bulk refurbishment and replacement programs are considered to achieve economies of scale. Generally speaking all equipment requests are to replace failing existing equipment.

The one exception to this is some of the test equipment requests; much of this equipment is new, but is necessary to keep pace with changing technology needs. For example, some of this equipment is necessary for testing the health of fiber optic equipment not in use prior to 2005. This particular plan addresses three issues with respect to the Test and Communication equipment requested:

1. High failure rate of existing test sets;
2. Need for more equipment in each district because of increasing numbers of circuits to be tested;
3. Need to add the capability to test new protocols, specifically C37.94 and G.703 both of which are specific to digital relays communicating over a digital communications system. These new protocols were introduced to the system as part of a RAS upgrade. Being critical equipment,

transmission had to quickly identify and request test equipment capable of testing and maintaining circuits using these new protocols.

Key Drivers:
Equipment end of life issues (O&M costs and lost time costs exceed replacement)

- Equipment maintainability and availability (manufacturer is no longer in business so spare parts are no longer readily available)
- Equipment security and exposure to hazards (Homeland security & safety requirements)
- Obsolescence (equipment can no longer meet organizational needs)
- Legislative & regulatory compliance (equipment is required to meet new legal requirements)

All requests are reviewed by transmission technical services to determine if it would be more economic or practical to lease the request rather then purchase before recommending a purchase to the TEAP team.

3.2.6.1 Risk assessment

Context:

TS carries out an extensive process of prioritizing needs for new major equipment items based on condition assessments which take into consideration actual usage experience. Almost all items in this request will replace existing items that are at the end of their useful life and where extending useful life (e.g. via rebuilds) is no longer practicable. The exception is telecommunications equipment where more equipment needs to be purchased due to heavier communications demands on the grid or where technological obsolescence requires early replacement.

Risk Analysis:

Risks of Doing Project

- Possible but minor direct cost overrun under worst case (+20% of $5M or ~$1M total) due to rough cost estimates in proposal
- No adverse impact on reliability
- Possible and moderate adverse safety impact due to inexperienced users on new equipment

Risks of Not Doing Project

- Likely and major cost impacts due to maintenance delays and expensive work around (e.g. equipment rentals, rebuilds)
- Likely and major impacts on transmission grid reliability due to non-availability or breakdowns of equipment
- Possible and severe impacts on worker safety due to unsafe work environment from degraded tools

Evaluation:

The risk of the status quo (Not Doing the project) is believed to be unacceptable. Doing the project is believed to lessen TS' total risk relative to Not Doing the project across cost, reliability and safety dimensions of risk. In short, doing the project is believed to reduce T's total risk.

3.2.7 Maintenance Programs

The BPA system maintenance program provides for the maintenance of substation electrical equipment, transmission lines and rights of way, communications, and protection and control.

The maintenance program is designed to minimize failures and realize the optimum service life of the equipment and facilities once they are installed and place in service. Life cycle costs, a balance of the initial costs of installation and those of maintenance throughout a facility's life, help determine the selection of the power system equipment. Sound environmental practices are used for all maintenance activities. All work practices are performed with safety as a first priority.

The preventive maintenance program is designed to maintain reliable service for our customers and protect BPA's capital investment. Diagnostic testing is performed to prevent or forecast impending equipment failure and to determine when equipment has reached the end of its service life. The maintenance organizations respond to system emergencies and make repairs to restore service as quickly as practical. Maintenance crews perform some construction activities and reimbursable work for customers. The reliability centered maintenance concept is used to determine specific maintenance tasks and service levels.

3.2.7.1 Maintenance Programs

Preventive Maintenance

The preventive maintenance program is work performed to keep equipment and facilities in operating condition and to prolong service life. Preventive maintenance consists of performing standard tasks which lead to the completion of a maintenance service. Tasks are managed and schedule in the PassPort Work management module which are scheduled at intervals prescribed in the Preventive Maintenance Guides. Preventive Maintenance work orders are automatically generated in PassPort.

Corrective Maintenance

Corrective maintenance is non-forecast work performed to restore service following a failure. Corrective tasks are required based on equipment needs rather than the Preventive Maintenance Guide. Corrective Maintenance work orders are manually generated for each event.

3.2.7.2 Contingency Response

Crew distribution and size

Maintenance crews are geographically located throughout the BPA' service area. Field crew locations have been selected and are periodically reviewed to assure timely response to various forms of trouble or emergencies. In addition, crews from other districts, areas, and organizations such as Construction can be called upon to assist a local district. Mutual aid agreements have also been made with BPA customers and other utilities to provide assistance to BPA or to customers.

Maintenance crews are sized to perform the preventive and corrective maintenance workload within a district without incurring excessive backlog. A combination of in-house and contractor personnel as well as the prudent use of overtime resources are applied to accomplish the maintenance workload.

Materials for Emergencies

Appropriate spare inventory is maintained by Materials Management to enable restoration in the event of a failure. This stock is referred to as the 500kV System Spare inventory and the Emergency Maintenance Minimum (EMM) inventory for each category of equipment. This equipment can only be withdrawn from stock and installed to replace failed equipment with consent of the corresponding maintenance organization.

Other stocks that can be accessed under emergency conditions are the Transmission Unplanned Project Contingency (TUPC) and Substation Unplanned Project Contingency (SUPC) inventories, direct change equipment associated with construction projects, and equipment pending disposal at Utilization and Disposal (U&D).

More transmission equipment is available for emergencies under a mutual assistance agreement with other member utilities of the Northwest/Southwest Intertie Transmission Reliability Committee.

Specific Response Plans

Environmental Spills:

Each substation must have a plan in place to respond to environmental problems such as oil spills. The plan will be posted in a conspicuous place.

Telecommunications:

The Power System Control Maintenance organization implements and periodically tests an emergency microwave restoration plan. The restoration system is sufficient to replace a complete radio repeater site including the building, antenna structure, batteries and other equipment. The restoration equipment is planned to restore a single failed site within 72 hours or less. Refer to Section 4.5.3 of the Reliability Criteria's Control Chapter.

Transmission Lines:

The Transmission Line Maintenance organization maintains portable Lindsay restoration towers which can be quickly and efficiently erected to temporarily replace failed structures. . Emergency maintenance spare stocking levels of transmission line hardware, conductor, poles and steel shall provide the ability to restore 1.6 kilometer of failed transmission line at any voltage.

Transformers:

Sufficient mobile spares are located and maintained to provide emergency restoration of a failed customer service transformer within the time stipulated in the Reliability Criteria for Customer Service. Adequate spares will be available to replace failed main-grid or sub-grid power transformers within 90 days.

Control Centers:

The control center maintenance organization maintains continuous monitoring of the communications system and energy management systems for both control centers. These employees provide the first level of restoration support or coordination for communication and control center outages. Data systems, software, and communications maintenance crews will be trained, experienced, sized and located appropriately to provide the required level of response to control center problems.

3.2.7.3 Maintenance Programs

Lines

Description:

Transmission Line Maintenance is responsible for the maintenance of transmission lines including airway markers, line sectionalizing switches, line rights of way and line access roads.

Substation

Description:

Substation Maintenance is responsible for the maintenance of power transformers, power circuit breakers, disconnect switches, station batteries and chargers, reactors and capacitors, cable and other high voltage electrical-equipment within the substation.

System Protection Control

Description:

System Protection Maintenance is responsible for the maintenance 9f protective relays, revenue metering, recording and annunciator equipment, control circuits, local remedial action scheme equipment, and the interconnecting, low-voltage circuitry for control and indication of high voltage equipment status.

Power System Control

Description:

Power System Control Maintenance is responsible for the maintenance of BPA's operational communications and control systems. This equipment is an integral part of the power system and provides for critical services such as microwave and. carrier current transfer trip, supervisory control and data acquisition, telemeter, remedial actions for control of power system stability, telephone communications, land mobile radio service, and - support systems such as engine-generators, communication batteries, and battery chargers. The backbone of the BPA communications system is a large, redundant microwave radio system supported by light route microwave, power line carrier, VHF /UHF radio, and fiber optics.

Data Systems Maintenance

Description:

Data System Maintenance is responsible for performance monitoring, scheduled and emergency maintenance of data acquisitions equipment, control system hardware (including central remedial action controllers), and support systems at BPA's control centers.

Data Systems Software Maintenance

Description:

Data Systems Software Maintenance is responsible for correcting and modifying control and data acquisition system software including that of central remedial action controller software. This function keeps the computer tools used by Dispatching, Scheduling and management current with the power system configuration. Additionally, responsibility for all aspects of operational databases, display and user interface software maintenance resides with this group.

Environmental Protection

Description:

Environmental Protection is responsible for developing programs, processes, and procedures which ensure that environmental risks associated with transmission system operations, maintenance, and construction activities are eliminated or reduced.

Non-Electric Plant Maintenance

Description:

Non-Electric Plant Maintenance is responsible for the maintenance of BPA facilities including yards, buildings and grounds, roads and parking, railroad and transfer tracks, fuel dispensing systems, and station and building utilities.

Heavy Mobile Equipment Maintenance

Description:

Heavy Mobile Equipment mechanics are responsible for maintenance of BP A's fleet of bucket trucks, personnel lifts, cranes, backhoes, caterpillars, transmission line stringing' equipment, specialized district GSA vehicles, and the engines associated with substation and radio station engine-generators.